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BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of:) Docket No. 19-IEPR-03
)
2019 Integrated Energy Policy) RE: Electricity and
Report) Natural Gas Demand
) Forecast
_____)

IEPR COMMISSIONER WORKSHOP ON THE
2019 CALIFORNIA ENERGY DEMAND PRELIMINARY
ELECTRICITY AND NATURAL GAS DEMAND FORECAST

WARREN-ALQUIST STATE ENERGY BUILDING
1516 NINTH STREET
1ST FLOOR, ARTHUR ROSENFELD HEARING ROOM
SACRAMENTO, CALIFORNIA 95814

THURSDAY, AUGUST 15, 2019

10:53 A.M.

Reported By:

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P R O C E E D I N G S

1
2 AUGUST 15, 2019 10:00 A.M.

3 MR. FUGATE: Okay, thank you, everyone. Again,
4 sorry for the delay. Appreciate your patience. We're
5 going to go ahead and get started.

6 Welcome to today's 2019 IEPR Commissioner
7 Workshop on the Preliminary Energy -- California Energy
8 Demand Forecast.

9 I'm Nick Fugate with the Energy Commission's
10 Assessments Division. And I'm going to run through a
11 few housekeeping items real quick.

12 Restrooms are in the atrium, out the door and to
13 your left. If there's an emergency and we need to
14 evacuate, please follow staff to Roosevelt Park. It's
15 directly across the 9th and P intersection.

16 The workshop is being broadcast through our
17 WebEx conferencing system, so just be aware that
18 everything is being recorded today. We'll post the
19 audio recording to the Energy Commission's website in
20 about a week, and the written transcript in a month.

21 At the end of the workshop, there will be an
22 opportunity for public comments. We're asking parties
23 to limit their comments to three minutes. For those in
24 the room who would like to make comments, please fill
25 out a blue card and give it to me. And when it's your

1 turn to speak, please come up to the center lectern and
2 speak directly into the microphone. It's also helpful
3 if you can identify your name and affiliation for the
4 record. And if you have a business card, please leave
5 it with our court reporter.

6 For WebEx participants, you can use the raise
7 hand feature and we will call on you during the comment
8 period.

9 Materials for this meeting are available on the
10 website and hardcopies are on the table, at the
11 entrance.

12 Written comments on today's topics are due in
13 two weeks. That's Thursday, August 29th. The workshop
14 notice explains the process for submitting written
15 comments.

16 And, finally, I'd like to thank everyone for
17 being here today. I'll remind everyone, one last time,
18 if you're speaking, please identify yourself for the
19 record.

20 And with that, before we begin our
21 presentations, I'll turn it over to the dais for any
22 comments.

23 COMMISSIONER MCALLISTER: All right. Thank you,
24 Nick, appreciate it. Again, really appreciate
25 everybody's patience. It's a very rare occurrence,

1 actually, that we start late. Usually, we're right on
2 time. So, apologize for that.

3 My name's Andrew McAllister. I'm the Lead
4 Commissioner on energy efficiency and energy
5 assessments, and looking at, and leading the forecasting
6 work this year.

7 And a lot is going on with the forecasting. I'm
8 going to be brief, actually, so we can kind of make up a
9 little bit of time. One thing I wanted to say, we still
10 will stop at 11:45 and we still will pick up at 1:15. I
11 have to be in the capitol building from noon to one.
12 So, that we'll just go as far as we can until 11:45, and
13 then pick up at 1:15.

14 So, obviously, the forecasting is bread and
15 butter for the Energy Commission. At the same time --
16 you know, we've been doing it for a long time, but at
17 the same time there is a lot of innovation happening in
18 this space. We're firmly in the digital age. We have
19 access to a lot more data than we ever have. And we
20 also need a lot more information than we ever have
21 needed to be able to do forecasting in this new, complex
22 energy environment that we're in today. With
23 distributed energy, with all the great technologies,
24 with really looking to a much diverse set of resources,
25 most of which are distributed or many of which are

1 distributed. And looking at how we can anticipate
2 what's coming in a much more robust, and localized, and
3 increasingly temporal way.

4 So, our forecasting kind of to-do list gets
5 bigger, even as we have all these tools to help us
6 answer a lot of these questions.

7 So, you are all part of this discussion and we
8 need your creativity and vision, as well, to inform what
9 we're doing. And, you know, we realize there's an
10 audience for this forecast that has to digest it and use
11 it, and including across the other agencies, the PUC,
12 and the ISO, and many other folks outside of this
13 building.

14 So, it really is a big lift, with lots of
15 participation. At the same time, it's a little bit, you
16 know, for the uninitiated, a little bit obtuse and a
17 little bit of a foreign language. So, our effort with
18 these workshops is to not have it be insider baseball as
19 much as possible. And really, try to have a
20 conversation that is informed by as many stakeholders,
21 as many knowledgeable stakeholders as possible, so we
22 can have a product that really stands up over time.

23 And so, there's the forecast itself and then
24 there's the methodology. And at the same time, we're
25 doing the forecast this year, we're also thinking about

1 the methodology and how that's going to evolve going
2 forward. And so, there are multiple sort of layers to
3 this. I think probably more so this year than perhaps
4 in the past.

5 We have a great team on this, who will, in their
6 turn speak, and I have a lot of confidence in the work
7 that they're doing. And, hopefully, that will come
8 across in the presentations.

9 And your comments, coming in to help inform the
10 next steps, are equally critical. So, really appreciate
11 everyone coming today, both here in the room and online.
12 And really looking forward to comments and insights
13 along the way as we proceed through this year's forecast
14 development.

15 And I want to thank Nick and the team. I see
16 Cary, and Chris, and the whole team here with us, and
17 you'll hear from them in turn.

18 And then, in the afternoon, the utilities and
19 their individual presentations and contributions.

20 So, I'm grateful to be joined by Rhett deMesa,
21 Commissioner Janea Scott's Advisor, who is -- I think
22 Janea is the Lead Commissioner on the IEPR overall this
23 year, and couldn't be with us today. But we have Rhett
24 in her stead. So, Rhett, do you want to make any
25 comments.

1 Okay. All right, well, I think we're ready to
2 back to you, Nick.

3 MR. FUGATE: Okay, thank you. I'm going to kick
4 things off with a short presentation on just the purpose
5 of the forecast and the preliminary forecast.

6 So, the forecast lays the foundation for a
7 number of State-sponsored planning activities. At the
8 CPUC, it feeds into the integrated resource planning
9 process, distributed resource planning, and also informs
10 the Resource Adequacy Program.

11 At the ISO, it informs transmission planning and
12 flexibility studies. And, importantly, it provides
13 important information for setting and tracking progress
14 toward the State's energy and climate goals.

15 So, the reason we do a preliminary, you know,
16 it's a sort of check in with stakeholders. It's a first
17 look at the impacts resulting from a new set of inputs,
18 assumptions, and modeling changes. It also gives us an
19 opportunity to compare our forecast against the most
20 recent utility forecasts that we have, that are
21 submitted through our IEPR Demand Forms every two years.

22 You know, the forecast feeds into other Energy
23 Commission assessments of electricity and natural gas
24 systems. So, it's important for us to produce this
25 preliminary forecast so that the results from those

1 dependent processes can feed back into our revised
2 forecast in the form of, for example, new rate
3 projections.

4 And we leave enough time between the preliminary
5 and the revised forecast such that we can make changes
6 for the revised based on discussions internally, and
7 with stakeholders.

8 So, we do produce a forecast of natural gas end-
9 user consumption. Our focus today, though, will be on
10 the electricity demand forecast, and user consumption,
11 retail sales, annual and monthly peaks, and hourly
12 demand. Our base here for both sales and peak will be
13 2018. And the forecast period extends through 2030.

14 We're presenting here, today, only our baseline
15 forecasts or forecasts that account for committed
16 standards and program impacts. We have some discussion
17 today of additional achievable efficiency, AAEE, but
18 that will be focused on our process for developing those
19 scenarios, rather than on actual results.

20 I will note that there are a few components of
21 what had previously been considered additional
22 achievable that are now part of our committed
23 assessments of efficiency.

24 Some program impacts in federal appliance
25 standards, but perhaps most notably, the 2019 Title 24

1 Building Standards are now on the books. And so, for
2 this cycle, we won't be developing any AAPV scenarios.
3 those compliance-driven, system adoptions are now going
4 to be part of the baseline.

5 To develop the 2019 preliminary forecast, we
6 conducted a full set of model runs. We refreshed our
7 rate projections and economic drivers. We've
8 incorporated another year's worth of historical load
9 data, system interconnection data, and forecast data
10 provided by load-serving entities. Which, among other
11 things, give us further insight into the CCA landscape
12 over the next two years.

13 We've developed new projections for important
14 load modifiers, such as electric vehicles, self-
15 generation, and committed efficiency.

16 And we've begun incorporating results from our
17 load-shape project with ADM. Our hourly model, for
18 example, now incorporates new electric vehicle charging
19 profiles.

20 And as part of our effort to provide more
21 localized forecasts, we incorporate information that may
22 have a significant impact on future load for smaller
23 LSEs. For the preliminary, this includes our forecast
24 for Valley Electric Association, which we adjusted to
25 account for sizeable planned cultivation facilities that

1 are not captured in our previous forecast.

2 For the revised, we'll be refreshing our drivers
3 again, make sure that we have the latest economic
4 projections. DOF, the Department of Finance, will
5 providing a new household forecast and we'll update our
6 rate projects again.

7 By the start of October, we'll have recorded our
8 summer peak for 2019, so we'll create a new weather-
9 normalized starting for our peak forecast.

10 Over the next couple of months, our efficiency
11 team will be developing AAEE scenarios. And so, by the
12 revised, we'll have a new set of managed forecasts.

13 Expanding on a 2017 staff analysis of potential
14 energy impacts from cannabis cultivation, we plan to
15 include projected impacts in our 2019 revised forecast.

16 And there will be some modeling enhancements.
17 Some, as our presenters today will discuss, are the
18 results of ongoing work. But others may arise in
19 response to stakeholder comments and discussions
20 following this workshop.

21 And, lastly, I want to acknowledge that some
22 stakeholders have expressed an interest in including
23 impacts of fuel substitution in the forecast, perhaps by
24 utilizing our additional achievable framework. This is
25 clearly a reasonable and likely necessary objective,

1 given State goals around building decarbonization. But
2 there's a great deal of uncertainty around the range the
3 potential decarbonization strategies that could play
4 out.

5 AAFS would be a particularly complex piece of
6 analysis, one that would have to be reconciled with our
7 efficiency impact analysis with our hourly modeling
8 work, and with our end-use models.

9 Similar to AAEE, we would have to translate AAFS
10 impacts to specific loads buses, though right now we
11 have no data on the schedule and location of potential
12 retrofits.

13 And so, for these reasons, we will not be
14 developing AAFS for Commission adoption as part of the
15 2019 IEPR cycle. Instead, we're proposing to present,
16 alongside our revised forecast, a preliminary analysis
17 of potential AAFS impacts. Importantly, this analysis
18 would outline additional data and analytic issues that
19 need to be overcome before AAFS is ready to be adopted.

20 At the revised forecast workshop later this
21 year, will likely be a venue for this discussion.

22 Which brings me to my last slide here, some
23 important dates. These are the anchor points for the
24 remaining forecast schedule. August 29, written
25 comments are due in response to this workshop.

1 September 26 is a workshop we have planned for emerging
2 topics related to forecasting. December 2nd is another
3 workshop where we will present and discuss our revised
4 forecast. And January 2020 is, whatever the business
5 meeting date ends up being for that January will be when
6 we're planning to present the forecast for adoption.

7 And so, unless there are comments from the
8 Commissioner, I'll invite our second speaker, Ingrid
9 Neumann, to discuss additional achievable energy
10 efficiency.

11 MS. NEUMANN: Hi. I am Ingrid Neumann and I
12 will be presenting on additional achievable energy
13 efficiency, specifically on the process, like Nick
14 mentioned, as we are then designing the scenarios and
15 we'll have some numbers in October, and the final
16 numbers in November. So, more about that at the end,
17 but let's talk about the process, first.

18 So, for those of you who don't know, additional
19 achievable energy is an hourly load modifier to the
20 baseline forecast, so that's the context here for the
21 demand forecast.

22 So, before I go into that process, I wanted to
23 mention what the difference is between SB 350 and AEE,
24 because we do use a lot of the same data streams, but
25 they have very different goals.

1 So, like you can see on the slide, SB 350
2 projections are used to identify whether the potential
3 of programmatic targets achieve the doubling goal that
4 was set by the Energy Commission. So, that's the goal
5 to double the energy efficiency from 2015 by January 1st
6 of 2030.

7 Now, AAEE projections are actually incremental
8 baseline -- or, incremental to the baseline demand
9 forecast and serve for resource planning and procurement
10 needs. So, this is always forward looking and it's
11 specific to modifying the demand forecast.

12 So, SB 350 is fixed to a 2015 base year and
13 you're always measuring with respect to that. Whereas,
14 the AAEE, as I mentioned, is always forward looking, so
15 it has a rolling base year that rolls forward each IEPR
16 cycle.

17 For the uncertainty, SB 350, the first time it
18 was measured was in 2017 and there was only one scenario
19 for it. So, there was only one item there. But for
20 2019, we've added some capability of having different
21 options or different scenarios, if you will, for SB 350
22 projections. So, you'll see that in a separate
23 proceeding.

24 So, AAEE, as you know, does have a very
25 elaborate process of scenario design, which condenses

1 the uncertainty of specific elements into scenarios that
2 range from being conservative to much more optimistic.

3 So, some agencies use SB 350 as a proxy for a
4 very high-efficiency scenario. But for AAEE, we
5 actually have explicit agreements to use specific
6 scenarios for resource planning and transmission
7 planning studies. So, there's an end consumer at the
8 end.

9 So, the implications of falling short of the
10 targets, that's something that only applies to SB 350,
11 because we want to see how we're doing with energy
12 efficiency with respect to the goals that were set for
13 SB 350.

14 So, now, let's put our lens completely on AAEE
15 for that process. And I wanted to -- before I show you
16 the flow chart for that, I want to highlight some
17 process improvements that we've made from the 2017 IEPR
18 cycle to the 2019 IEPR cycle.

19 So, we've improved the analysis of decay and re-
20 participation. This is for all of the data streams that
21 are being used. We are using cumulative results from
22 the IOU/PG study for IOU program savings. So, we have
23 the -- we retain the same decay and replaced rates that
24 are used in the PG study there.

25 Similarly, for the POU model, we retain those

1 decay and replace rates. And what we've done for this
2 cycle is we've actually added some more capability to
3 having not just the one scenario that's reported in the
4 CMUA report, but have more conservative options, so we
5 can actually have variation in the scenarios. Also, for
6 the POU programs. We didn't have that before.

7 Then, we've updated and expanded the Beyond
8 Utility Program workbooks that were originally developed
9 in the last SB 350 cycle. And the workbooks are
10 embedded in a new tool that assigns end-use level decay
11 based on EUL. We have a total of 20 workbooks, now,
12 including fuel substitution. It's very limited for new
13 construction, so I wanted to say that in context with
14 what Nick had spoken about previously.

15 Then, conservation voltage reduction and we
16 added workbooks for the agricultural and industrial
17 sectors. So, we're capturing more areas of savings.

18 And then, we have improved attribution to sector
19 and end use. This is very important because as we
20 developed the new hourly tool for AAEE, because it is an
21 8760 hourly load modifier to the baseline forecast, we
22 want to have, by the specific end uses, the correct or
23 the most correct mapping to the new load profiles that
24 we have available to us.

25 So, we are creating 8760 hourly projects from

1 annual AAEE savings for the 10-year forecast period.

2 And last, but not least, we are improving the
3 natural gas demand analysis because building
4 decarbonization is an emergency --? Well, an emerging
5 is what I'm trying to say, but there are those that, you
6 know, we need to think about building decarbonization.
7 So, it is a policy emphasis and that would have us
8 refine our gas demand analysis.

9 All right, so here is the beginning of our flow
10 chart. We have three main data sources. The first
11 being for the CMUA PG study, for the POU projections.
12 And these are for their program projections.

13 And the second being the IOU program
14 projections, found in the CPUC's PG study that was
15 recently, or release this year.

16 And then, lastly, the Beyond Utility Programs,
17 which are captured in these workbooks in-house.

18 So, all of those projections need to be created
19 into AAEE scenarios. Right, there's not just one number
20 there that we'll have. So, we need to look at the POU
21 projections, and we've created to have a capability of
22 having some variation there, so that we can build those
23 scenarios being conservative to optimistic.

24 And, similarly, as we did in 2017, we will do
25 the same thing for the IOU program projections.

1 So, within the tool that we have created, that
2 handles the workbooks, there is also a capability of
3 designing AAEE scenarios for the Beyond Utility
4 Programs, so that's in here. So, everything becomes the
5 six AAEE scenarios that we will have.

6 And there's some added intricacy as far as codes
7 and standards. So, codes and standards we get -- so,
8 this is Title 20 appliance, the federal appliance
9 standards, and Title 24. We get contributions from the
10 PG study, from the IOU PG study, as well as future code
11 cycles that are not captured there in our Beyond Utility
12 workbooks. So, that's what that up and down arrow is
13 showing us. That we need to make sure that we capture
14 everything once, you know, and that there is some
15 interaction.

16 So, you know, it could be three data streams or
17 four data streams that all need to come together as six
18 scenarios for each piece, for each of those elements,
19 and that goes into this master scenario. And that's the
20 scenario design.

21 So, this is all by utility, by sector, by end
22 use, and then for each of the six scenarios. And, also,
23 it's for electricity demand, as well as natural gas
24 demand. And this is on an annual basis.

25 Now, the electricity demand is then further fed

1 through this hourly tool that we've developed and will
2 give us also by sector, or end use, and by scenario 8760
3 results for each hour in that ten-year forecast.

4 All right. So, since we have completed one
5 cycle in 2017 recently, right, we are really repeating
6 the same type of process with the added refinements that
7 I mentioned in my first slide. So, I wanted to show you
8 what a complete grid might look like with all of the
9 scenarios developed.

10 So, we're starting here with the final 2018 CPUC
11 PG study. So, these are the five scenarios that were
12 presented in the PG study from the last cycle. Now, one
13 of those is adopted by the CPUC as the goals for the
14 IOUs. And that's the scenario that we use in the middle
15 and build our scenarios around.

16 So, we would take that grid and fill in more
17 conservation options using all of those levers in that
18 colored bar. Right, we have, you know, building stock,
19 retail prices, you know, different program assumptions
20 that we would work with the IOUs and the CPUC with in
21 order to determine what variation is feasible there.
22 And then, as well as cost-effectiveness threshold that
23 can be made more lenient or more stringent, depending on
24 if we want a more conservative or optimistic scenario.

25 So, this was how it was filled in for the last

1 IEPR cycle, for the IOU contributions. So, that's for
2 the programs. But then, you might be able to see, I
3 don't know it's very small, and the details are
4 dreadfully important for today's discussion because
5 these are from last time. But the bottom bar shows us
6 that we need to eliminate any duplication with the
7 baseline forecast. Right, because we are trying to
8 modify the baseline forecast, so we don't want to count
9 anything twice.

10 So, if you're looking at, you know, some of the
11 shading, it's not quite as nice here, right, we would
12 need to subtract that out so that we count everything
13 only once. Okay.

14 So, then, the bottom bar of the scenarios here
15 are the codes and standards that are captured in the
16 Potential and Goals study. So, we look at those. We
17 can have different compliance rate reductions. We can
18 have enhancements to that. We can include various code
19 cycle vintages, or not include them, depending on what's
20 appropriate for each scenario.

21 So, we do take those IOU attributable savings
22 and they are scaled up to total savings. And then, we
23 additionally, because we don't just want savings for the
24 IOU territories, but for the entire State of California,
25 we then scale to statewide savings and allocate the

1 shares based on electricity sales to the POU's, and POU
2 groupings. This is actually very important for the
3 small POU's that reside inside the CAISO SERFs or the
4 CAISO planning area, which is important for, you know,
5 resource adequacy and planning needs from that source.

6 So, this one bar here, you might not have seen
7 before because this is the one POU AAEE scenario that
8 was used last time. So, the POU's, for their program
9 potential savings, they submit in the CMUA report one
10 option. So, we didn't build around that option, we just
11 used that one option for each of our six scenarios.

12 This time, we have the capability of building
13 around that, similarly to how we did that for the IOU
14 programs.

15 So, then, we move on to Beyond Utility. That
16 could stack down, but then it just gets even larger.
17 So, I promise there is a slide in a couple of slides
18 ahead that has everything in its full glory.

19 So, for the Beyond Utility workbooks, we do kind
20 of tend to separate those into Beyond Utility Programs,
21 and then the actual codes and standards savings. So,
22 this top bar is the codes and standards savings. We
23 want to consider only codes and standards future
24 ratchets that are not already captured in the PG study
25 and, of course, that aren't the baseline forecast.

1 Right, it's all about capturing it exactly once.

2 So, everything is scaled to statewide and
3 allocated to the utility territories. And again, you're
4 careful to eliminate any other duplication.

5 So, now we are here for the 2019 IEPR cycle and
6 we propose to do very much -- use a similar framework.
7 So, this is, what's filled in is that mid-scenario,
8 which is the scenario that the CPUC is looking at for
9 IOU goals. Right, so we would build around that, make
10 more conservative estimates, as well as make more
11 optimistic estimates. So, we haven't filled that in,
12 yet. So, you have opportunity to comment on that, if
13 you like.

14 So, we have the same types of levers that we can
15 tweak, right, for the programs, for the cost
16 effectiveness, for the econ demo models, and such.

17 Again, we're looking at the codes and standards,
18 taking a portion of that from the PG study, and scaling
19 it up so that you get total savings for each of the
20 territories, be the IOU or POU.

21 And, then, we have the POU scenarios, which are
22 new this time. We are able to build around that one
23 reference. I mean, there aren't as many levers for this
24 as there are for the IOU scenarios, but there are some
25 levers where we have an expanded measure list. We can

1 increase and decrease incentive levels. And, you know,
2 decide on what's appropriate for the retirement of
3 programs and that sort of thing. So, there are some
4 variations that we can build scenarios around.

5 And then, lastly, for our in-house effort, we've
6 had a very large contractual effort for the Beyond
7 Utility workbooks this cycle. The workbooks were
8 originally developed for SB 350 purposes because we were
9 trying to capture all energy efficiency savings
10 possible.

11 Right, but in doing so, we realized that some of
12 this is appropriate to include in the demand forecast,
13 as well, as AAEE modifies the baseline. So, that's what
14 we will be looking at doing more of.

15 Right now, the inputs are loaded to the maximum
16 savings potential, so they're very optimistic because
17 they are to measure progress towards the SB 350 savings
18 goals.

19 And then, as a reminder, if you did look at the
20 2017 IEPR cycle, for the Beyond Utility that was
21 included in 2017, only Prop. 39 was included in the
22 first five scenarios. Only in the last, in the sixth
23 scenario, the high plus scenario, were some of the other
24 program workbooks included, and at discounted rates.
25 So, they were scaled down from that maximum savings

1 potential for inclusion in AAEE.

2 So, we would be looking at what -- you know, how
3 do we include or how much do we include for each of
4 these programs, in each of the scenarios based on how
5 conservative or optimistic that scenario's intended to
6 be.

7 So, the workbooks do vary in level of
8 sophistication, but they all have various savings
9 parameters that can be adjusted. So, we do have quite a
10 bit of flexibility using low, mid and high IEPR econ
11 demo drivers. There are conservative reference,
12 aggressive and aggressive savings estimates defined for
13 each program, and individual workbooks. And then, we
14 can have an individual weight assigned to the program
15 workbooks included here.

16 So, those program workbooks, the 20, right, are
17 listed here. The codes and standards work a little bit
18 differently. They have a little special line. But it
19 gives us an idea of what kind of flexibility we might
20 have. So, I'm giving you a visual representation of how
21 one might pull some of those levers here.

22 So, for Title 24, for example, you can decide at
23 which year, so which code cycle you end the inclusion
24 at. So, you could include only through 2022, or you
25 could include through 2025. You know, which of those

1 code cycles do you include up to?

2 Then, you can do this differently for new
3 construction, as well as for additions and alterations.
4 And then, of course, for the residential and commercial
5 building sector you can have those levers be different.
6 So, similarly, you can do this for Title 20 and the
7 federal appliance standards.

8 All right, so here it is in its full glory. We
9 do have both the IOU potential program savings and the
10 codes and standards savings for the blue and the pink
11 bars are coming from the PG study. And then, there are
12 additional codes and savings in the Beyond Utility
13 Program Savings as part of those three workbooks that
14 exist in there. And then, we have the POU potential
15 program savings.

16 So, this is what we would fill in for our final
17 scenario definitions, when we have the six AAEE
18 scenarios for this code cycle.

19 So, all of that, in that box, goes over to the
20 right-hand box that's boxed in orange. And so, that's
21 our whole scenario design process and then we could run
22 all of that through the hourly tool.

23 So, a little bit more on the hourly tool. We've
24 mapped the 48 named end uses to the new ADM load shape
25 profiles, and we've supplemented that with Navigant load

1 shape profiles using the 2017 forecast, where needed.

2 The input menu for this tool allows selection of
3 forecast start and end year, so it's somewhat future
4 proofed in that way because, of course, there's a
5 rolling date for those ten years.

6 And then, the utility IOUs, the main POUs, and
7 then for the small POUs we have them in north and south
8 groupings. So, put output out by utility and then you
9 and select, if you wanted, just at the sector level or
10 if you want full sector end use level, 8760 for
11 electricity, for all ten years of the forecast.

12 And you can also include or omit transmission
13 and distribution losses. And as I mentioned, the
14 outputs are 8760 hourly results for each scenario, for
15 each forecast year.

16 So, our schedule is aggressive, right. We're
17 working very hard. Formal comments, as Nick mentioned,
18 are due on the 29th, but the sooner you get them to us,
19 it is appreciated, right, as we are working.

20 The September 26th, there's another IEPR
21 workshop on emerging issues. And we'll put our AAEE
22 scenario designs as a portion of that. So, that's the
23 first time we will be able to present those scenario
24 designs and take comments on those. But if you have
25 comments on how you might think that we ought to do it,

1 that's also helpful at this point.

2 And then we, the first time we'll have hourly
3 results internally will be October 1st. And then, we're
4 giving ourselves a month to clean those up, take your
5 comments into consideration further, and have those to
6 the forecasting unit to modify that baseline demand
7 forecast.

8 So, questions or comments?

9 COMMISSIONER MCALLISTER: Thanks, Ingrid, that
10 was great. So, you know, we do briefings regularly on
11 this, so I don't have a lot of questions. I do want to
12 talk about a couple things, though.

13 So, you know, Nick talked about how, you know,
14 we're not quite ready to do AAFS in fuel substitution.
15 You know, we're gathering tools and data, and I think
16 that's a reasonable thing going forward. I think
17 stakeholders are really going to want to talk about that
18 and, rightly so, you know, it's kind of a hot topic and
19 it's necessary going forward.

20 And I guess I'm wondering sort of in that realm,
21 you know, there's a bunch of things. There's a lot
22 going on at the PUC, in particular, about this. And on
23 the one hand, you know, the portfolio, sort of I think
24 there's a staff paper out right now that sets goals
25 going forward for the new portfolio that will get

1 discussion. A little bit of shifting between programs
2 and codes and standards savings.

3 And then, there's also the recent decision on
4 the three-prong test. And so, there's a lot of
5 discussion about how the portfolio funds will -- you
6 know, the traditionally considered, you know, energy-
7 efficiency portfolio funds might be migrating in a
8 significant way over to fuel substitution, because the
9 three-prong test is getting easier.

10 So, where does that kind of migration fall into
11 the AAEE? How much of that is likely to be -- if we're
12 really looking at the portfolio and trying to figure out
13 what the impacts are, you know, how much of that is sort
14 of fuel substitution and how much of that is efficiency
15 portfolio in terms of, you know, modeling what's likely
16 to happen going forward?

17 Is that a discussion we're going to have or is
18 that something there are already some thoughts about?

19 MS. NEUMANN: I suppose it will be a discussion
20 that we will have, right. I don't think we're ready to
21 do this at this point. There's just still too much
22 uncertainty.

23 COMMISSIONER MCALLISTER: I mean, that makes
24 sense. I guess I would sort of ask all the stakeholders
25 to weigh in on this --

1 MS. NEUMANN: Uh-hum.

2 COMMISSIONER MCALLISTER: -- because I think
3 there's a lot of uncertainty about how much the industry
4 is actually ready to actually do that. And as projects
5 get proposed, as the PUC's third-party process -- you
6 know, they're going to bid out programs to third
7 parties, for the most, this portfolio. When those
8 proposals come in and some of them, many of them,
9 possibly, are for fuel substitution, that's going to
10 really impact, potentially, the near term of what
11 happens out there in the world that we need to capture.
12 We need to capture it somewhere in the future load
13 shapes, you know, in the future, different wedges that
14 we're putting together. Whether it's the codes are on
15 the DR side or, you know, the EE side or, you know,
16 other parts of the forecast so -- or, other components
17 of the forecast.

18 So, I think that's a complexity that, really,
19 we're not going to be able to avoid -- well, not that we
20 want to avoid it. But just we're going to have to
21 engage with that, I think, pretty clearly.

22 I had a specific question about the load shapes.
23 So, the hourly work, are we using the data from mainly
24 PG&E, but perhaps other utilities that have leveraged
25 the NMEC, the Normalized Meter Energy Consumption data

1 to look hourly impacts of efficiency measures from the
2 programs? There are some interesting experiences that
3 have actually shown load shapes of savings, you know,
4 sort of the hourly savings shapes for different end
5 uses, for specific programs.

6 And PG&E was kind of the pioneer on that, but it
7 seems to be taking hold and I think will in this
8 portfolio going forward.

9 MS. NEUMANN: We're using the ADM load shapes
10 that were developed as part of that contract.

11 COMMISSIONER MCALLISTER: Okay, okay, so that --

12 MS. NEUMANN: Yeah, but this is interesting,
13 yeah.

14 COMMISSIONER MCALLISTER: Yeah, there's some
15 really interesting work being done with the metered
16 energy data, hourly data, sort of, you know, gathering
17 up participants and programs to figure out the hourly
18 profile of savings. It seems like Chris may be aware of
19 that.

20 And that's likely, I think, to promulgate more
21 throughout the programs. So, Chris, maybe you've been
22 talking to them about that?

23 MR. KAVALEC: I just wanted to mention that ADM
24 is developing load shapes, plus an hourly load model,
25 which houses all those different load shapes.

1 COMMISSIONER MCALLISTER: Uh-hum.

2 MR. KAVALEC: And the idea is that ADM provided
3 us load shapes based on the best information they could
4 gather at the time. But the model is set up to
5 introduce new load shapes as we get new information.

6 So, certainly, if we get better information on
7 efficiency load shapes, then that would replace what ADM
8 has included.

9 COMMISSIONER MCALLISTER: Okay, great. So, you
10 know, the CalTRACK tool over at -- that PG&E developed,
11 and it's getting some good traction.

12 MR. KAVALEC: Yeah.

13 COMMISSIONER MCALLISTER: I think that's got a
14 lot of data in it that will be useful for us.

15 MR. KAVALEC: Yeah.

16 MS. NEUMANN: Yeah, the AAEE hourly load model
17 will also accept any load shapes in it, fully
18 calendarized as well. So, that's a possibility.

19 COMMISSIONER MCALLISTER: That's great. Thanks
20 a lot, that's all the questions I have.

21 MS. NEUMANN: Thank you.

22 MR. FUGATE: Okay, our next presenter is Cary
23 Garcia to review the CED -- no, I'm sorry -- yeah, the
24 preliminary forecast results.

25 MR. GARCIA: All right. I made a last-minute

1 adjustment to my slides, so I'm just making sure I'm
2 looking at the right one. I was also trying to slow
3 down for this presentation, but it looks like I might
4 have to speed up a little bit. Eleven-forty-five is the
5 time, right?

6 COMMISSIONER MCALLISTER: Yeah, we have until
7 11:45, so if you can bang it out without losing content,
8 that would be great.

9 MR. GARCIA: Okay. I'll probably breeze through
10 some of the earlier stuff, though. I just wanted to
11 give a quick overview -- oh, I should introduce myself.
12 I'm Cary Garcia, I'm attempting to be the lead
13 forecaster for the Demand Forecasting Office.

14 And so, I just wanted to give an overview of our
15 demand model system and I'll get into the statewide
16 results that we have developed for the preliminary
17 forecast this year.

18 So, I'm going to start off with the demand model
19 systems. And so, as we kind of talked about earlier
20 today, we have some of the modeling inputs at the top
21 here. And so, as we mentioned, we have the economic and
22 demographic information, so that's largely going to come
23 from Department of Finance and Moody's Analytics.

24 We have our efficiency information and demand
25 response that will go into the models, as well. As well

1 as the electricity and natural gas consumption data we
2 collect through our QFER, which is our Quarterly Fuels
3 and Energy Reporting system.

4 And so, this year, I should also mention, we did
5 an update. So, in the previous forecast, the Energy
6 Update 2018, we were using 2017 history. And so, now,
7 we've included 2018 history for electricity consumption,
8 which is a combination of the measure -- or, estimated
9 electricity generation from self-generation, like PV for
10 example, as well as the actual utility sales that are
11 reported to us.

12 And so, that information, those three items at
13 the top feeds into our three buckets of models. So, one
14 being the transportation and energy demand models. Mark
15 will talk about the light-duty electric vehicle forecast
16 a little bit later, that's within that.

17 We have our sector models that are broken out by
18 specific sectors. So, residential, commercial, AG,
19 industrial, mining. Let's see, TCU, which is
20 telecommunications, utilities, as well as like street
21 lighting in there.

22 And then, we have our self-generation model that
23 does our forecast of PV capacity and generation impacts,
24 as well as other self-generating, like combined heat and
25 power, for example.

1 And as I mentioned, some of that information
2 coming out of the self-gen model is going to feed back
3 into that electricity and natural gas consumption data
4 to recreate what consumption would be. Which, as I
5 mentioned, is the aggregation of what the sales was and
6 then what we estimate the generation from our
7 consumption from self-generation would be.

8 And so, the output from those three buckets
9 there feeds into our summary model, where we do various
10 calibration and adjustments for weather, for example.
11 And then, from that summary model, that's going to feed
12 into our peak demand and hourly model that we'll talk
13 about later today.

14 And then, right at the very bottom, we get to a
15 preliminary and later this year a revised forecast.

16 And so, just breaking down the demand scenarios
17 that we use. So, we have three primary demand
18 scenarios, the high demand scenario, which generally has
19 higher economic and demographic information. It also
20 has climate change, that I'll talk about a little bit
21 later, and electric vehicle forecasts. And those will
22 be high impacts for all of those.

23 Counter to that, we have lower electricity rates
24 and self-generation, as well. The idea being that with
25 those lower rates, at least to create a nice balance in

1 that high scenario, you would expect higher electricity
2 usage. Then if you have those lower rates, it would
3 also make self-generation less economic. And so, you'd
4 have less self-generation adoption.

5 In the low demand case, it's the antithesis of
6 that for the economic and demographic information, as
7 well as electric vehicles. But as I said, now we have
8 higher rates, which is going to do the inverse of what I
9 mentioned before for the high demand case. So, now, you
10 would have higher rates and, therefore, higher self-
11 generation in the low demand case. Therefore, lowering
12 that demand case.

13 And in the low demand case, we don't have
14 climate change, either.

15 Now, in the mid demand case, that's essentially
16 in between, obviously, our high and our low cases. But
17 we also include a moderate amount of climate change in
18 that and I'll talk about that a little bit more.

19 And so, this is just a quick break out of our
20 electricity planning areas in the State. We have about
21 eight planning areas, including Valley Electric
22 Association that we talked about. Those bold items are
23 highlighted because that's -- you'll probably see in the
24 agenda those are the items that I'm going to focus on
25 later today, when I discuss the planning area forecasts.

1 So, just a little bit about statewide drivers.
2 As I mentioned, we use Moody's Analytics primarily for
3 our economic and demographic information. But for
4 population and household information, we use Department
5 of Finance information for those.

6 Although, we do modify the household forecast to
7 use Moody's projection of that to give us a better
8 spread in our high case scenario.

9 But otherwise, you can see in the bottom there
10 the population estimates are the same as last year. A
11 slight change in the household projects, but you'll
12 notice the mid and the low are the same, as I mentioned.

13 And then, we do have some reductions in the
14 personal income, which is going to drive your
15 residential forecast. Usually, we use personal income
16 per capita. So, given the population's the same, we're
17 going to have a lower income per capita there.

18 And then, also, manufacturing output which is
19 going to affect our industrial and mining sectors.
20 That's been reduced a little bit in comparison to last
21 year.

22 But our commercial employment is about the same.
23 Some of these numbers are rounded, so there is a small
24 decline, but relatively close to the same as last cycle.

25 But the overall picture here is that

1 manufacturing output goes down a little bit, as I said,
2 which affects those industrial sectors. And then, with
3 the personal income decline relative to the previous
4 forecast is going to bring down your residential
5 forecast a tad bit.

6 Now, I'm going to get into some of the other key
7 components that we include in the forecast. So, as we
8 talked about -- sorry, Nick talked about earlier this
9 morning, we did roll over program savings that otherwise
10 was not included last year. Now, we've moved forward to
11 2019, and so we're going to include the new program
12 savings that was previously a part of the AAEE analysis.

13 So, ultimately, this shakes out to -- it
14 basically peaks in 2019. That's when these new programs
15 are going to start, and then they're going to decay off.
16 And then, you would have AA would get developed, again,
17 and you would see some new program savings added on into
18 the forecast. But for right now, we're not including
19 any AA scenarios in our baseline forecasts.

20 But, ultimately, this is about 19,500 gigawatt
21 hours in 2019. And as I said, that starts to decay as
22 program savings declines. And about 4,500 gigawatts are
23 going to come from the POU's in our forecast.

24 And so, we get this information primarily from
25 the CEDARS database, from the CPUC. Since we're trying

1 to educate a little bit more, that actual acronym is the
2 California Energy Data and Reporting System.

3 And then, we get the POU information from SB
4 1037 reports for the POUS.

5 And in addition to the committed savings from
6 programs, we also included new codes and standards
7 savings, so that will be the Title 24 savings for
8 residential buildings and commercial sector.

9 We also included some more federal appliance
10 standards, as well. And so, that will be added into
11 this baseline forecast. And that will cause a
12 difference compared to last year. We have these new
13 standards that will come in, so that's going to increase
14 that savings relative to the last cycle.

15 Here's the climate change scenarios that I was
16 mentioning. So, as I mentioned, we don't have a low
17 scenario for that. So, the low scenario will assume no
18 climate change impacts. But we do include a high
19 scenario of climate change in the respective high
20 scenario and, likewise, in the mid scenario.

21 And so, these impacts are primarily going to
22 happen in your heating and cooling sectors, where
23 they're the most temperature responsive. So, obviously,
24 residential and commercial sectors are going to get
25 adjusted by this.

1 And so, what we do is we develop an econometric
2 model that basically teases out what that temperature
3 response is going to be. Scripps Institute of
4 Oceanography develops these scenarios for us.
5 Essentially, a higher change in temperature and then a
6 moderate change in temperature. And so, given that we
7 have a temperature response, we simply apply the trend
8 for that high scenario to get us what that -- to
9 determine what that impact would be in terms of gigawatt
10 hours or therms, for example, in a gas consumption gas.

11 I'll pause here real quickly, if there are any
12 questions along the way from your guys. All right.
13 this stuff is pretty routine here. We're getting to the
14 more interesting stuff.

15 So, I don't want to take some of Mark's thunder
16 right now, but this is just a brief overview of the
17 light duty electric vehicle consumption. So, 15,000
18 gigawatt hours by 2030. You can see the red line up
19 there is our previous forecast and our blue line is the
20 new mid case from the preliminary forecast.

21 You'll definitely see the distinction there.
22 It's slightly lower. And that's going to be the result
23 of an allocation of more residential electric vehicles
24 versus commercial. And then, when you do that, it's
25 basically residential vehicles are going to have a lower

1 VMT relative to commercial. And so, that will drive
2 down your electricity consumption impacts from the
3 overall light duty vehicle forecast.

4 And I should also note that the growth rates are
5 mainly the same. I think it's growing, right here in my
6 notes, roughly 13 percent on average from 2019 to 2030.
7 So, in comparison to like the residential or commercial
8 sector overall, it's a tremendous amount of growth in
9 those, in vehicles. And this is roughly three and a
10 half million vehicles statewide.

11 PV energy Impacts. Once again, I'll be brief
12 because Sudhakar is going to go over this today, this
13 afternoon. But the one thing to note is that you'll see
14 the distinction between our -- the red line there, once
15 again, the mid case from last year and the new mid case.
16 Roughly, a 5,000 gigawatt hour difference in 2030.

17 And one reason is that the overall PV forecast,
18 in terms of capacity went up a little bit. But there's
19 also, if you remember our last baseline, we included --
20 in our last forecast, we have our baseline forecast and
21 then we included AAPV for the Title 24. And so, now,
22 that's been wrapped up into our baseline forecast, and
23 so that's going to bump things up a little bit when you
24 look at this type of comparison.

25 This is an overview of the baseline consumption

1 forecast on a statewide basis. It's just comparing our
2 mid cases, over there on the left side, the preliminary
3 on the top and then the update on the bottom there. And
4 you can see, as I mentioned, the residential consumption
5 forecast. Once again, this is the combination of self-
6 generation and sales as to what your total consumption
7 would be for that sector. It's dropped down a little
8 bit, as I said, from that reduction in personal income
9 growth and relatively slow housing growth.

10 The commercial sector is growing a little bit
11 and that's primarily from the continued growth in
12 commercial floor space.

13 And industrial and mining, as I mentioned, the
14 manufacturing output information that we received from
15 Moody's showed a decline there. And you can see that
16 reflected here in these growth rates.

17 Agricultural is about the same. And then, TCU
18 has a slight reduction.

19 Looking at our baseline consumption in this
20 graph --

21 COMMISSIONER MCALLISTER: Hey, Cary, can I jump
22 in real quick? I'm going to have to go. I actually
23 have to walk over to the Capitol. But how far in are
24 you?

25 MR. GARCIA: I can probably --

1 COMMISSIONER MCALLISTER: There's a bit more.

2 MR. GARCIA: If you come back, I can probably
3 wrap it up pretty quickly and we can move on.

4 COMMISSIONER MCALLISTER: Yeah, I've got to walk
5 over. I can't keep the Legislature waiting, mostly.
6 But I think probably the best thing to do is to give a
7 little hiatus and come back at 1:15, if that's okay with
8 everybody. I do want to catch this.

9 MR. GARCIA: Okay.

10 COMMISSIONER MCALLISTER: So, okay. So, let's
11 see, so, Nick, is there anything else to say? Anything
12 else to say to folks, where the good restaurants are or
13 whatever?

14 MR. FUGATE: Yeah, sure. So, anyone looking for
15 food who's in the building, you know, we have a new
16 market. If you just walk a couple blocks up to 9th
17 Street -- I get turned around which direction it is. Up
18 9th Street. And then, you know, there is also a food
19 truck, I think right outside. If you walk out the front
20 of the building and take a left.

21 So, we will reconvene at 1:15. Thank you,
22 everyone.

23 (Off the record at 11:47 a.m.)

24 (On the record at 1:18 p.m.)

25 COMMISSIONER MCALLISTER: All right. Well,

1 thanks for sticking around. There's a little bit
2 sparser audience than there was this morning. I guess,
3 maybe, lunch was really good and they're lingering.

4 MR. FUGATE: Or they melted.

5 COMMISSIONER MCALLISTER: Yeah, or they went
6 outside and melted, yeah. But thanks for adjusting the
7 schedule. I appreciate that for giving us a little more
8 time between the morning and the afternoon.

9 And, so, anyway, I had to brutally cut off Cary,
10 so we'll get started where we left off.

11 MR. GARCIA: That's fine. I backed up just a
12 little bit to get to the consumption part. This is
13 really where we get into like the actual numbers.

14 So, just to reiterate, really quickly again, you
15 may remember this chart. So, we have this decline in
16 the residential sector consumption. Commercial sector
17 grows a little bit there. And you'll see that, as I
18 mentioned earlier, the industrial and mining sectors
19 declining due to the reduction in -- I think they're
20 adjusting my volume. Okay, it was too loud.

21 And then, agricultural, once again, remains
22 about the same, as well as TCU, although a slight
23 decline overall across the State.

24 And so, looking at these graphs here, so I'm
25 comparing the history against our previous forecast.

1 That's the red line and CEDU, the California Energy
2 Demand Update 2018 mid case, against our new high, mid
3 and low cases for this preliminary forecast.

4 So, as I note here, it's about five percent
5 lower. Obviously, we have a lower, 2018 actual, as I
6 mentioned before. We were using the 2018 value from the
7 2018 forecast, was that forecasted value using 2017
8 consumption data.

9 COMMISSIONER MCALLISTER: Hey, Cary, this is not
10 weather normalized, right?

11 MR. GARCIA: We do a slight weather
12 normalization, actually.

13 COMMISSIONER MCALLISTER: Huh.

14 MR. GARCIA: So, you'll see a little tick down,
15 like a little hockey stick at the very end there, in
16 2019.

17 COMMISSIONER MCALLISTER: Yeah.

18 MR. GARCIA: And that's going to be the
19 adjustment. We basically start from average weather in
20 the forecast, but we make an adjustment using actual
21 weather compared to the 30-year average. So, that's
22 what brings that down a little further there.

23 COMMISSIONER MCALLISTER: Oh, okay.

24 MR. GARCIA: So, the 2018 it's starting from is
25 the actual, actual and then it drops down a little bit

1 more in the 2018 period.

2 COMMISSIONER MCALLISTER: Okay. Okay.

3 MR. GARCIA: You can quote me on the "actual,
4 actual."

5 COOMISSIONER MCALLISTER: The actual, actual,
6 yeah. So, but that's a -- I mean, what is that, about
7 40,000 gigawatt hours difference just right off the bat?

8 MR. GARCIA: Yeah, right off the bat there.
9 Ultimately, the growth rates are about the same. So, in
10 the -- let's see here, I'm looking at my numbers. So,
11 yeah, it's a 3 percent reduction just in that 2018
12 value. That 5 percent lower is actually a little bit
13 later in the forecast. But the growth rates are 1.2
14 versus 1.3 percent, ultimately, comparing the two mid
15 cases. And the high case is about one and a half
16 percent. As I mentioned, we had a higher household
17 forecast for the high case. You see that go much higher
18 than the other two cases. And the low case is going at
19 just under 1 percent.

20 COMMISSIONER MCALLISTER: Okay. You have this
21 for capacity, as well? This is energy sales?

22 MR. GARCIA: No, this is actually total energy
23 consumption. So, this is going to include --

24 COMMISSIONER MCALLISTER: For energy
25 consumption, yeah.

1 MR. GARCIA: Yeah, it includes the sales --

2 COMMISSIONER MCALLISTER: Oh, right, I gotcha.

3 MR. GARCIA: -- for self-generation.

4 COMMISSIONER MCALLISTER: Yeah, I gotcha, I
5 gotcha, okay.

6 MR. GARCIA: Right. I have a slide later on
7 where I get into the sales forecast.

8 COMMISSIONER MCALLISTER: Okay, got it.

9 MR. GARCIA: And this is our usual graph of
10 consumption per capita. So, essentially, just taking
11 that consumption and dividing it by the population
12 projections that we have. And as we saw in the previous
13 graph, we have a lower baseline consumption. So, that's
14 going to reduce our per capita estimates.

15 But similar growth rate, similar to the
16 consumption I showed before, just a minor difference in
17 growth rate, so .4 percent versus .5 percent in the last
18 forecast. And that adjustment that you saw, dropping it
19 down to the new, historical starting point is evidence
20 here as well.

21 This next slide breaks down that consumption
22 forecast into the sectors that we use in our models.
23 And so, at the top there you can see the residential and
24 commercial sectors are the bulk of electricity
25 consumption in the State.

1 And then, light-duty electric vehicle
2 consumption is going to be added into those two sectors
3 as well, and so that's going to have them also grow a
4 little bit faster than the respective sectors.

5 And you can see at the bottom, we have the
6 industrial, AG, TCU, and the mining sectors, as well as
7 street lighting. It's a very small sliver. I think
8 it's like a fraction of a percent of statewide total
9 when you look at the numbers there. But you can see
10 those are pretty flat in terms of consumption. As I
11 mentioned, industrial and those sectors have been pretty
12 flat for well over a decade, and so we see that
13 continuing into the future with a little bit, a slight
14 decline at the end there.

15 If you're actually -- like, in percentage terms,
16 the industrial sector is around 12 and a half percent of
17 the statewide total consumption and AG is around 6 and a
18 half percent relative to those commercial sectors,
19 commercial and residential combination of about 70
20 percent.

21 And that remains pretty constant from the
22 starting points. It grows a little bit but you can
23 obviously see that that Dutch share kind of takes the bulk
24 of it.

25 This is the sales forecast. So, in this case,

1 it's the consumption minus the self-generation that
2 we're forecasting, so it gives us the total electricity
3 sales that the customers are ultimately buying in their
4 sectors.

5 So, once again, a lower 2018 actual in compared
6 to the last forecast. And here, we can see the increase
7 in the behind-the-meter PV capacity that's going to
8 cause that reduction, a slight slow down in growth.
9 Ultimately, it's around .6 percent for that mid case, in
10 blue, compared to the red line that is our old forecast
11 is around .9 percent growth. And that's going from 2019
12 on average per year to 2030.

13 And you see that the low case there is pretty
14 slow. And then, also keep in mind there's a little bit
15 of climate change. But it's going to be -- we're using
16 similar projections as last year, so that won't cause
17 any differences. But that's also incorporated in our
18 high and our low cases, as I mentioned earlier this
19 morning.

20 Just for reference, too, the high case is about
21 1.2 percent compared to the .6 that we have now. And
22 the low case, obviously, is about zero, as you can see
23 from the graph here.

24 And I'm just reiterating, again, you really see
25 that slow down in the industrial and mining sector,

1 causing that reduction in growth, as well as a little
2 slightly slower growth in the residential sector.

3 And it's similar to the consumption break out
4 that I showed. And so, now, you can really see the
5 impact of that PV generation there, flattening those
6 residential and commercial sector forecasts out. And as
7 I said, there's a little faster growth in commercial
8 sector PV, which is going to slow down those commercial
9 sales relative to the residential sector forecast.

10 And then, here is the statewide coincident
11 peaks. So, this includes both the IOUs, as well as the
12 other planning areas that I mentioned this morning. So,
13 ultimately, if we're having a -- going to have a slower
14 sales growth, then you'll have a slower growth in peak
15 demand. And then, also, there's going to be a peak
16 shift included that bumps things up a little bit. And
17 so, we only incorporate that for the IOUs, which we
18 model on an hourly basis, that Chris will talk about
19 later today. But, ultimately, that shakes out to about
20 4,200 megawatts of additional peak demand, relative to
21 the previous way we forecasted, which did not account
22 for the impacts of DER. So, PV and light-duty vehicles
23 on an hourly basis.

24 Then here, this is a last-minute addition. We
25 had to make a few tweaks to our natural gas consumption

1 forecast. And so, this is actually end-use natural gas
2 consumption forecast. So, once again, similar, the same
3 models that we're using for the electricity side and,
4 basically, the same drivers, but slightly different
5 because you're looking at, obviously, natural gas usage
6 as the end uses versus the electricity end uses.

7 And so, here, we can see that adjustment from
8 the QFER 2016. So, slightly different than the previous
9 comparison. We didn't do a natural gas update, as we do
10 for electricity. So, this is comparing against the CED
11 2017 forecast.

12 The few notes that I have here. So, we're not -
13 - we mentioned before and Nick mentioned this, we're not
14 incorporating any fuel or significant building
15 electrification this round, but we'll look at that for
16 the 2021. There's going to be sort of -- it's inherent
17 in the name, there's a substitution going on. So, if
18 there's an increase in electrification for like heating,
19 and water heating, and space heating, there would be a
20 decline on the end-use natural gas side that would be
21 comparable.

22 So, we're including a small amount of natural
23 gas vehicles in here, as well. So, by 2030, that's
24 ultimately about 150 million therms of natural gas
25 vehicles, which is a slight increase in comparison to

1 the last forecast.

2 You also see that big jump up in consumption,
3 from 2018 to 2019, and that's also weather adjustment in
4 the residential and commercial sectors. So, basically,
5 the 2018 historical HDV is a little bit lower than the
6 historical 30-year average. As I mentioned before on
7 the electricity, that jump over there.

8 And this is especially true for SoCal Gas and
9 San Diego Gas and Electric. So, it's affecting the
10 Southern California portion of the State.

11 Ultimately, growth in all three scenarios has
12 dropped compared to 2017, and that's most because of the
13 2019 Title 24 standards, as well as a reduction in
14 growth in the mining sector. So, similar things playing
15 out in terms of gas, as with electricity that I
16 mentioned before.

17 The 2019 mid case also falls relative to the
18 2019 mid case. You can see how -- or, the low case.
19 You can see how they kind of both match other by 2030.
20 And that's going to be due to climate change. So, we
21 don't have any climate change in the low scenario. But
22 as I mentioned, we do include it in the high and the
23 mid. But what's happening over here is that it's going
24 to be affecting climate change in terms of heating
25 degree days. It's actually going to bring your heating

1 degree days a little bit, so you're no longer be using
2 space heating. You won't have as much space heating
3 based around natural gas, so that's going to bring that
4 down to match the low case there.

5 And that's all I have for this. I'll just leave
6 as questions or comments there.

7 COMMISSIONER MCALLISTER: No, it's pretty clear.
8 I guess the one question I have, just about the natural
9 gas, is that there's not a whole lot of difference
10 between the mid and the low. And is that just because
11 the climate change impacts aren't -- I guess, what else
12 could affect the difference between -- what else changed
13 between low and mid, or is it pretty much just the
14 climate change impacts that got put in?

15 MR. GARCIA: It's primarily going to be the
16 climate change impacts.

17 COMMISSIONER MCALLISTER: Okay.

18 MR. GARCIA: Yeah, so -- I always get the CDD
19 and HDD, I have to remember it's like one side of the
20 equation where --

21 COMMISSIONER MCALLISTER: Right, right, right,
22 right.

23 MR. GARCIA: So, in the heating degree days, if
24 it's a little warmer, you're going to have less heating
25 degree days.

1 COMMISSIONER MCALLISTER: Yeah.

2 MR. GARCIA: But you're going to have more
3 cooling degree days. So, on the electricity side it's
4 going to bump things up, whereas on the natural gas side
5 it's going to bring things down a little bit.

6 COMMISSIONER MCALLISTER: Oh, it's the same
7 conditions on the scenario.

8 MR. GARCIA: Exactly.

9 COMMISSIONER MCALLISTER: Yeah, okay, gotcha.
10 That makes sense.

11 MR. GARCIA: But it's almost -- I guess it's
12 probably almost similar to the fuel substitution kind of
13 idea, right.

14 COMMISSIONER MCALLISTER: Yeah.

15 MR. GARCIA: Like if you're making a reduction
16 on one side, replacement is going to happen. But it
17 just so happens --

18 COMMISSIONER MCALLISTER: Yeah.

19 MR. GARCIA: -- it occurs with the climate
20 scenarios.

21 COMMISSIONER MCALLISTER: Yeah, got it. Thanks.

22 MR. GARCIA: I have no idea who's up next. I
23 didn't look at the agenda. Nick, please help.

24 MR. FUGATE: I keep forgetting we don't have
25 Heather here today. So, next we have, our next speaker

1 is Mark Palmere, and he's going to present on our
2 electric vehicle forecast.

3 MR. PALMERE: Good afternoon Commissioners, and
4 stakeholders, and members of the public. I guess just
5 one Commissioner, I guess.

6 My name is Mark Palmere and I am with the
7 Transportation Energy Forecasting Unit. And I'd just
8 like to present a brief overview of our transportation
9 electricity demand forecast. And that includes both
10 light duty vehicles, as well as medium, heavy duty
11 freight, and public transportation. So, this is the
12 overall transportation electricity demand.

13 To start with, I'd like to look at some
14 historical slides. This shows PEV sales over the past
15 decade or so. And as you can see, they've been rising
16 quite dramatically, starting with, you know, only a few
17 thousand in 2011 and 2012. And by 2018, they eclipsed
18 150,000 sales annual for the first time ever.

19 Through March of this year, which is the latest
20 where we have what we consider reliable data, there have
21 been approximately 560,000 light duty PEVs sold in the
22 State of California.

23 And another way of looking at the sales numbers
24 is by looking at the PEV sales for the share of overall
25 light duty sales. Again, you can see 2010, 2011 very

1 low numbers, but by 2018 it got to has high as 8 percent
2 of overall sales for either BEVs, battery electric
3 vehicles, or PHEVs, plug-in hybrid electric vehicles.

4 And, you know, based on the numbers we've seen
5 so far, we do expect that trend to continue. And that's
6 sort of what I'm going to talk about a lot is our
7 forecast future trends.

8 And then, I would also like to talk about the
9 difference between the two types of PEVs. So, we hear a
10 lot about PEV sales and goals as the number of PEV
11 sales. But PEVs aren't all created equal, especially
12 when it comes to electricity use. Where BEVs use 100
13 percent electricity, PHEVs do not because they can also
14 run on gasoline. So, it's important to distinguish
15 between the two in our forecast, which we do.

16 And, historically, PHEVs were more popular than
17 BEVs. Back in 2012 and those early years, for example
18 the Chevrolet Volt was one of the best selling PEVs on
19 the market and it's a PHEV. So, that's why you would
20 see more PHEVs. But for a number of reasons, Tesla not
21 the least which, BEVs have been gradually gaining share
22 among PEVs. And it surpassed 50 percent for good, so
23 far in 2015, and by 2018 it was over 60 percent of PEVs
24 sold were BEVs. And we do expect that trend to continue
25 for a number of reasons. But based on our attribute

1 forecast, which I will go into, in more details, the
2 conditions seem to be more favorable for BEVs. And
3 coupled with historical data, we do expect to see more
4 BEVs than PHEVs.

5 As I mentioned, vehicle attributes, this is sort
6 of what we use to determine our forecast numbers. We
7 use a number of attributes, both from the vehicle side,
8 from the consumer side, and from the general econ
9 demographic side. These are just the vehicle attributes
10 which do account for regulatory requirements.

11 And for light duty vehicles, the attributes
12 include range, price, fuel economy, acceleration, number
13 of models available, refueling time, maintenance cost,
14 cargo capacity. And we do weight them by importance
15 based on our California vehicle sales. So, these are
16 not all considered equally in our forecast.

17 Because in our vehicle survey we ask the
18 respondents to sort of choose vehicles based on
19 hypothetical attributes, and we use that to model how
20 important people find each specific attribute.

21 Unsurprisingly, price is consistently considered
22 the most important attribute. Range and fuel economy
23 are also very important. So, you know, the other ones
24 on that list, you know, cargo capacity, acceleration,
25 it's not that we think they're unimportant, it's just

1 that they aren't weighted as much. But they are
2 definitely considered and we do model those attributes
3 as well, going through 2030.

4 And all this leads us to our forecast, which is
5 shown here. This is by all fuel types. Obviously, this
6 workshop is about electricity demand, so we're going to
7 focus on the red and the purple lines, and that
8 indicates BEVs and PHEVs, respectively.

9 The graph starts at 20 million. Everything
10 below that is all gasoline. But you can see, as we move
11 forward, the gasoline numbers aren't really increasing
12 and that's partially because BEVs and PHEVs, to a lesser
13 extent, are forecast to increase by a quite large
14 amount.

15 And this is the --

16 COMMISSIONER MCALLISTER: Hey, Mark, can I jump
17 in and ask a question about that?

18 MR. PALMERE: Uh-huh.

19 COMMISSIONER MCALLISTER: So, this takes into
20 account all the fuel economy increases and everything,
21 so these are absolute numbers of gas consumption, right?

22 MR. PALMERE: Oh, sorry, I should have
23 clarified. This is vehicle --

24 COMMISSIONER MCALLISTER: Proposed vehicle
25 population. I'm sorry. I'm glancing at it and trying

1 to multi-task and I didn't --

2 MR. PALMERE: Yeah. No, I should have clarified
3 that.

4 COMMISSIONER MCALLISTER: Okay.

5 MR. PALMERE: But, yeah, we will do --

6 COMMISSIONER MCALLISTER: Okay, so this is
7 population of cars. Okay, I got you.

8 MR. PALMERE: This is the number of vehicles on
9 the road.

10 COMMISSIONER MCALLISTER: I got you.

11 MR. PALMERE: Yeah, so we have gasoline --

12 COMMISSIONER MCALLISTER: Yeah, thanks. Sorry
13 about that.

14 MR. PALMERE: Oh, yeah, no problem.

15 And then, as I mentioned, the attributes, I had
16 that slide about vehicle attributes. This slide sort of
17 characterizes -- it may be a bit hard to read. It may
18 be easier on your handout. But I'll just go over it,
19 briefly.

20 So, we've got vehicle attributes, so we've also
21 got incentives and preferences. So, the preferences,
22 not only do they weight the importance of the
23 attributes, but they also measure consumers' preferences
24 for PEVs in general, versus other fuel types.

25 Whereas, there's like an inherent value of a

1 vehicle being a certain fuel type. And based on our
2 surveys, we do find that consumers, all else being
3 equal, do prefer BEVs and PHEVs to gasoline vehicles.
4 And not only is that the case, but based on our modeling
5 we increased that preference through the forecast in
6 every case, but our low case, due to the fact that as
7 the vehicles become more prominent on the road, people
8 will become more aware of them. And, as a result,
9 likely more interested in them.

10 COMMISSIONER MCALLISTER: Uh-hum.

11 MR. PALMERE: Incentives, that's another really
12 important one. We have the federal and state credit and
13 rebate, respectively, as well as carpooling access. And
14 we do have those being phased out in the middle of the
15 next decade, based on our assumptions of, you know, how
16 much it would cost and what it would do to the funding.
17 We kind of expect in our mid case the rebate to be
18 phased out at around 2025. But in the more optimistic
19 cases, we have it continuing through the forecast.

20 The same with HOV lane access. The federal tax
21 credit, that one's a little more consistent throughout
22 our different scenarios because they do have a set
23 language in place about where it is phased out for
24 manufacturers that reach over 200,000 sales. And so, we
25 are decreasing the effect of it based on when we expect

1 manufacturers to have reached that. Tesla and GM
2 already have, so it's already being taken into account.

3 Then, the attributes, as I mentioned, so the
4 price is the most important one in our model. And these
5 are based on -- our overall vehicle prices are based
6 heavily on battery prices because that is one of the
7 main components, and one of the barriers to lower costs
8 of EVs. Batteries are still quite expensive.

9 But based on our modeling we have, you know, in
10 the reference case it's down to \$100 per kilowatt hour.
11 But in our high case, it's down to \$80 per kilowatt
12 hour. And in our aggressive case, which isn't
13 officially a part of the IEPR, but just a modeling
14 exercise, it's also -- it's down to as low as \$70 per
15 kilowatt hour.

16 We've gotten some questions about price parity.
17 That's kind of a trending topic. People want to know
18 when is it going to be equal to EVs -- or, equal to
19 gasoline vehicles. And the answer is not as simple as a
20 number because what we do, is we measure it by different
21 classes of vehicles. So, there's going to be some
22 classes we forecast where it will get very close to
23 gasoline price parity, but not as much in others.

24 And that's just a factor of what, like what
25 makes are available, whether it's like a more upscale

1 class availability, then it's less likely to reach
2 parity. So, there's no like set answer to that. But in
3 our forecast, the prices are definitely a lot more
4 competitive and they -- even in the reference case, they
5 get very close to gasoline, even if they don't quite
6 reach them.

7 And then, range right now, it's over 300 miles
8 by 2030 in all of our cases. Refueling time is lower
9 and so is the time to stations, which measures how far
10 people have to go in minutes to get to the nearest
11 station.

12 COMMISSIONER MCALLISTER: Uh-hum.

13 MR. PALMERE: And all that gives us the numbers
14 by PEVs. So, we saw the overall distribution, but this
15 is just PEV-specific. So, in our reference case we have
16 about 3.6 million PEVs on the road in 2030. In the high
17 case, it jumps up to 4.6 million. And in the aggressive
18 and bookend case it's over 5 million.

19 And these are all, you know, very positive
20 numbers compared to where we are right now. As we can
21 see, the black line is historical and the colored lines
22 are forecast numbers. And even in the low case, we have
23 over a five-fold increase. So, based on our forecast,
24 things are definitely very optimistic for PEVs. And
25 that's due to a number of factors that I went over, the

1 lowering of prices, increased preferences, increased
2 availability, and the rebates.

3 And, as I mentioned, BEVs versus PHEVs, we saw
4 the historical graph of BEVs are becoming more popular
5 than PHEVs. Here, this is our forecast which kind of
6 continues that trend. By 2027 we have -- we are
7 forecasting over twice as many BEVs on the road, than
8 PHEVs, and that number will only increase based on our
9 forecast. And again, that's very important for
10 electricity consumption.

11 And then, I want to talk a little bit about
12 medium and heavy duty numbers. The battery electric
13 truck stock, in the mid and high case, is forecast to be
14 much higher than it is now. As much as 25,000 medium
15 and heavy duty trucks on the road in 2030 and about
16 10,000 in the mid case. The low case, that's less
17 favorable for battery electric technology. It's
18 expected to not really get off the ground. But in the
19 other two cases it is very optimistic for that, as well.

20 The same with the school bus population. This
21 is the mid case, I believe, and it's based on historical
22 numbers and the announcements. For example, the
23 announcement that the funding, the CEC-approved funding
24 for over 200 electric school buses. You can see that in
25 the chart that it's definitely expected to go up, as

1 well. And by 2030, our numbers have over 2,000 electric
2 school buses on the road, which is a really good amount
3 of progress.

4 And then, electric transit buses. And this is
5 modeled a little different than freight because so much
6 of what transit buses funding comes from, the government
7 -- the government funding, so it's easier to expect them
8 to use electric buses. So, that's why we see in all
9 cases electric buses are making a dent in the overall
10 number of buses, up to 3,000 to 5,000, depending on the
11 case. Which statewide, that's a very significant
12 number.

13 And all that leads up to our overall electricity
14 demand forecast. This morning, Cary showed the light
15 duty vehicle electricity demand forecast. And if you
16 have that chart out, you'll see that it looks very
17 similar because overall we expect a great majority of
18 the transportation electricity demand to be light duty
19 vehicles.

20 But as you saw in those recent charts, those
21 freight, buses, and school buses also expected to
22 increase their electricity demand.

23 And all of that leads to about 16,000 gigawatt
24 hours demand in 2030 in the mid case, but as high as
25 20,000 in the high case. And so, that's a very

1 significant amount of electricity. Obviously, we model
2 it at the annual level, so we don't focus as much on
3 load shapes, but it's something that is becoming more
4 and more relevant to the overall electricity demand
5 forecast. And we definitely are continuing to model it
6 and continuing to see positive trends for transportation
7 electrification.

8 And that is my last slide. I want to just talk
9 briefly about our team. I'm one of many, including our
10 new supervisor, Heidi, Anis Bahreinian, who is our lead
11 forecast and would be presenting this, but she is out of
12 the country, actually. Bob McBride is right there and
13 he is the one, our expert on freight modeling. Jesse
14 Gage does our DMV analysis. Elena Giyenko does ZEV
15 incentives, as well as the bus modeling. Ysbrand van
16 der Werf does fuel prices and urban modeling. And
17 Sudhakar Konala, who's presenting next on solar
18 attributes, does double duty, because he also does a lot
19 of ZEV attributes for us as well. And all of the
20 contact information is there, so if you have any further
21 questions about any specific topics, please feel free to
22 reach out to us. And we're also open for public comment
23 after the workshop.

24 COMMISSIONER MCALLISTER: Yeah, right.

25 MR. PALMERE: Thank you.

1 COMMISSIONER MCALLISTER: Thanks, Mark. It's
2 really, actually really phenomenal, the development of
3 these markets. I mean, you know, just from year to
4 year, the last, you know, six years, the last four
5 forecasts, or whatever, it's a whole different ball
6 game, now, in terms of the scale we're getting with EVs.

7 MR. PALMERE: Yeah, it's definitely changing
8 very rapidly. And even how we forecast it, based on new
9 developments and new technology, it changes every year.

10 COMMISSIONER MCALLISTER: Yeah, it's great.

11 MR. PALMERE: Thank you.

12 COMMISSIONER MCALLISTER: Thank you.

13 MR. FUGATE: So, our next presenter is Sudhakar
14 Konala, to talk about our self-generation forecast.

15 MR. KONALA: Good afternoon Commissioners,
16 stakeholders, members of the public. Today I'm going to
17 be -- I'm Sudhakar Konala, and I will be presenting the
18 self-generation forecast, but mainly I'm going to be
19 concentrating on the PV forecast.

20 So, just a brief overview of what I'm going to
21 be going over. So, I will briefly go over the forecast
22 methodology for the forecast. And then, I'm going to
23 review some historical self-generation information in
24 terms of capacity and energy.

25 Then, I'm going to go through our statewide

1 forecast before diving into individual forecasts for the
2 utility/planning areas. And, finally, I'll end up by
3 giving a brief overview of what to look forward to.

4 So, just to start off, I want to emphasize the
5 definition of our scenarios. So, as Cary mentioned, we
6 have three different demand cases, the high, the low and
7 the mid. What I really want to emphasize here is
8 something that's kind of counterintuitive, but it's
9 really important to understand. And that's that in the
10 high electricity demand case, we're modeling low PV
11 adoption. That's how we get high electricity demand.
12 And in the low electricity demand case, we're modeling
13 high PV adoption.

14 So, some of the assumptions related to PV
15 adoption are going to be reversed compared to the demand
16 cases.

17 So, here's a very high level overview of the
18 models that we use to forecast PV growth. We have
19 several different inputs that go into the models. They
20 include just historical statewide, installed behind-the-
21 meter PV capacity. But we also consider economic and
22 demographic data, specifically growth in households,
23 growth in commercial floor space, and residential and
24 commercial accounts. Also incorporated into the
25 forecast are electricity and natural gas prices. And,

1 finally, there were some PV-specific data that are
2 considered, such as system costs and performance.

3 And all of that information is fed into our
4 models. We have two primary models, which is the
5 residential sector predictive model and the commercial
6 sector predictive model. And then, for everything
7 that's not residential or commercial, we use a trend
8 analysis based on historical installations.

9 Out of these three models, we get an output of
10 statewide installed behind-the-meter PV capacity. And
11 then, we use capacity factors that are specified by 20
12 different forecast zones. And from that, we get a
13 forecast of energy generation for behind-the-meter PV.

14 I just want to emphasize that the residential
15 and the commercial sectors predict PV penetration based
16 on calculated payback period and bill savings, using a
17 bath diffusion approach.

18 Okay. I also want to take a little time
19 recapping AAPV, our additional achievable PV. In the
20 past, AAPV accounted for, at what the time was proposed
21 standards, for PV requirements for new homes.

22 Our baseline forecast forecasts adoption of PV
23 for new homes. But AAPV was defined as the difference
24 between PV adoptions for new homes due to the 2019 Title
25 24 regulations compared to what the market forecast was.

1 And that difference between the market forecast and the
2 regulations is the definition of AAPV.

3 So, in 2019, since the building standards
4 officially became law, we have incorporated AAPV into
5 the baseline PV forecast. So, based on this
6 information, our forecast of PV adoption for new homes
7 is now based entirely on regulatory compliance, rather
8 than a market forecast.

9 In terms of the assumptions of regulatory
10 compliance, they remain the same from previous
11 forecasts. So, in the low energy demand case, we're
12 assuming 90 percent adoption for new homes. In the high
13 case, it's about 70 percent, with the mid case coming in
14 at 80 percent.

15 Also, assumptions of the average PV system size
16 for new homes remains the same from previous forecasts.

17 I do want to make one point. In terms of the PV
18 forecast, I am going to be restating some of the results
19 from previous forecasts. The reason why I'm doing this
20 is because previous forecasts don't necessarily include
21 AAPV in the baseline. And if I were to present those
22 results, there would be a huge difference without having
23 a meaningful insight. So, it's my way of doing an
24 apples-to-apples comparison.

25 So, just a brief overview of the specific inputs

1 that were updated for the 2019 preliminary PV forecast.
2 We have a whole new dataset of PV interconnection data.
3 And most important of all from this is new data coming
4 from the 1304-B regulations. It's a new dataset that's
5 been available to us for this year, for the first time.

6 Also updated, economic and demographic data that
7 Cary Garcia went over. We also updated electricity
8 rates and electricity rate schedules, when appropriate.
9 And then, we updated historical PV system costs as well.

10 I briefly want to do an overview of the
11 interconnection data that we use to generate the
12 historical PV installation data. So, in gray are data
13 sources that we've used in the past. They still remain
14 part of the historical dataset, just because to update
15 the entire historical dataset is a large undertaking
16 that is reserved, probably, for an off-IEPR year.

17 But what I want to emphasize is that from the
18 last forecast to this forecast we do have several new
19 datasets, especially the 1304-B dataset. So, we relied
20 on that heavily to update installations through 2018.

21 Okay. So, now to some historical PV
22 installation data. So, at the end of 2018, there was
23 about 8,100 megawatts of total installed capacity. And
24 what we're seeing is that over the last three years the
25 PV market has been maturing, with installations

1 averaging between 1,300 and 1,400 megawatts annually.
2 And, specifically, we are seeing more growth in the
3 commercial market, with the residential market being
4 relatively flat over the last four years.

5 In addition to that, there was about 150
6 megawatts of energy storage that's been installed at the
7 end of 2018, 52 percent of which was in Southern
8 California Edison's territory. And of the 150
9 megawatts, about 90 megawatts of storage was installed
10 in the last two years alone. So, we do an acceleration
11 in storage going on, as well.

12 So, here I just have a list of installed
13 capacity broken down by some of the larger utilities,
14 and I guess the mid and major utilities as well. It's
15 just for reference, for anyone that's interested. I'm
16 not going to spend too much time going through it.

17 The main points I want to make is that the
18 large, the big five utilities, the IOUs, LADWP and SMUD,
19 they account for over 95 percent of the total installed
20 capacity in the State. And if you consider some of the
21 smaller ones, we're actually over 99 percent. So, that
22 is the updated dataset that we're working with for the
23 historical installed PV capacity.

24 So, with that, I'm going to get into the
25 forecast. First, I'll start with the statewide

1 forecast. So, here's a chart of self-generation, both
2 historical and forecasted for the State of California.
3 In 2018, there's an estimated 28,000 gigawatt hours of
4 self-generation in the State, roughly split 50/50
5 between PV and other.

6 As for the forecast itself, we assume that non-
7 PV self-gen, which is mostly combined heat and power, is
8 going to be relatively flat in the forecast period, and
9 this just reflects the trend in recent years. Over the
10 last four or five years, we don't see much growth.

11 But in terms of PV, we see it growing from about
12 13,800 gigawatt hours in 2018 to over 40,000 gigawatt
13 hours in the mid case. So, this represents almost a
14 three-fold growth in generation from PV by 2030.

15 Okay. So, if you guys have any questions at any
16 time, please feel free to stop me, otherwise I'm going
17 to keep going.

18 So, in terms of the PV forecast, as I mentioned
19 before in 2018 there was about 8,100 megawatts
20 installed. In the high electricity demand case, we
21 expect that to increase to about 19,400 megawatts. In
22 the mid case, to about 23,100 megawatts. And in the low
23 electricity demand case to about 26,800 megawatts.

24 And how this compares to the previous forecasts,
25 I have here as well. So, what we're seeing is we're

1 seeing a narrowing of the range compared to previous
2 forecasts. So, the low is slightly lower than the
3 previous lows, and the high is significantly higher than
4 the previous highs, and the mid is essentially an
5 average of the low and high. It's slightly higher than
6 previous mids.

7 The most important point to make about this,
8 specifically, is that the high is higher mainly due to
9 faster commercial growth, but also because actual 2018
10 installed PV capacity is much higher than we'd
11 previously projected, so that is affecting the
12 projections going forward.

13 COMMISSIONER MCALLISTER: So, Sudhakar, you
14 mentioned at the outset that the driver was primarily
15 sort of -- really, the consumer benefit, you know, the
16 rate and the cost, and sort of the, essentially, cash
17 flow model, I guess, or rate of return model.

18 MR. KONALA: Yeah.

19 COMMISSIONER MCALLISTER: Are we sure about
20 that? I mean, because there seems to be some kind of
21 market dynamic that people kind of get solar. You know,
22 there is some uncertainty around that metering. And so,
23 like I wonder how confident people are in that calculus,
24 but maybe decided to do it anyway. So, and maybe that
25 could explain some of this market strength.

1 MR. KONALA: Yeah. Yeah, I mean, in terms of
2 the financial auditing, it does make, you know, a lot of
3 sense to go to solar. So, and we are doing a financial
4 analysis, more than -- so, on the transportation side,
5 they do surveys and they do, I guess, preferences, and
6 we don't have that aspect in PV.

7 COMMISSIONER MCALLISTER: Oh, right, okay. All
8 right, got it, thanks.

9 MR. KONALA: Okay. So, I'm not going to spend
10 too much time on the next two slides, but I just wanted
11 to give some numbers out to stakeholders and members of
12 the public, so they could maybe review it and, if they
13 wanted to, come back with questions later on.

14 So, here, I just have projections of capacity by
15 each of the planning areas in 2030, and the differences
16 from the 2017 and 2018 forecasts.

17 So, in the mid case, again, the capacity
18 projection for statewide is about 23,000. That's about
19 a thousand megawatts higher than the 2018 IEPR forecast
20 an about 2,000 higher than the 2017 forecast.

21 I have similar numbers for energy, as well, so
22 if you have questions, just let me know.

23 Finally, for this section, I have a slide on the
24 contribution of the Title 24 standards. As I had stated
25 previously, we incorporated the contribution from these

1 standards into the baseline forecast, formerly known as
2 AAPV. The standards take into effect starting next
3 year. And, again, this is a forecast of regulatory
4 compliance. But there is a direct correlation with
5 these numbers and our forecast of new home construction.
6 So, if our forecast of new home construction changes,
7 then it's directly going to affect the contribution of
8 the standards to the PV forecast.

9 COMMISSIONER MCALLISTER: Those LADWP numbers
10 seem super small.

11 MR. KONALA: Yes. I was going to cover that and
12 the LADWP people are probably --

13 COMMISSIONER MCALLISTER: Okay. You know, go
14 ahead. That's fine, you can do it when you wanted to do
15 it, that's fine.

16 MR. KONALA: Okay.

17 COMMISSIONER MCALLISTER: I mean, SMUD, I mean,
18 their territory is so much larger, they're number of
19 customers is larger than SMUD.

20 MR. KONALA: Actually, I'll cover it now, since
21 we're on it. So, overall, LADWP numbers are not that
22 small. This is just only the contribution from new
23 homes. And this is directly related to the forecast of
24 new homes in LADWP. So, what we saw is the forecast for
25 new home growth for this year, for some reason the

1 growth is significantly slower. And that is something
2 we want to look into, to see why that happened.

3 But in the previous forecasts we have much
4 higher growth in LADWP and this year the growth was very
5 flat. So, that is leading to like very little growth in
6 the AAPV portion of the residential section -- or
7 sector.

8 COMMISSIONER MCALLISTER: Okay. But SMUD is so
9 radically different that it's tenfold?

10 MR. KONALA: So, it's the growth rate for
11 housing. I don't know the numbers off the top of my
12 head. LADWP was very small and SMUD wasn't very
13 significantly different from the previous forecast.

14 COMMISSIONER MCALLISTER: Okay. Okay, that will
15 be interesting to look into, yeah.

16 MR. GARCIA: Yeah, I think he noticed pretty
17 late --

18 COMMISSIONER MCALLISTER: Oh, okay.

19 MR. GARCIA: (Inaudible).

20 COMMISSIONER MCALLISTER: Yeah, okay, that
21 sounds good.

22 MR. GARCIA: Oh, yeah. Yeah, it's not just the
23 -- it's the calculation of additions, as well.

24 COMMISSIONER MCALLISTER: Okay.

25 MR. GARCIA: So, like the SMUD growth rate is

1 about 1 percent and the growth rate of the overall stock
2 is a little -- I think I talk about it in my
3 presentation later. I think it's a little below 1
4 percent, as well.

5 COMMISSIONER MCALLISTER: Okay.

6 MR. GARCIA: But then, when you start getting
7 into the additions and looking at what was added, we're
8 getting some peculiar numbers on that one. And I think
9 it's also due to how we're taking L.A. County, and we
10 have to share it out into our forecasting zones.

11 COMMISSIONER MCALLISTER: Uh-hum.

12 MR. GARCIA: So, we have LADWP split into two
13 zones. And that is kind of troublesome with those
14 little pockets, and how LADWP is split, so that causes
15 some issues. And we even compared that, our numbers
16 against what LADWP submitted in their demand forecast
17 for the IEPR, and there were significant differences in
18 the housing growth. So, as you said, we're going to
19 look into that.

20 COMMISSIONER MCALLISTER: Okay. Yeah, that
21 seems like kind of an outlier.

22 MR. KONALA: Yeah, it makes our overall demand
23 forecast difficult to compare as well.

24 COMMISSIONER MCALLISTER: Okay.

25 MR. KONALA: I guess the main point I'd like to

1 make is in terms of the Title 24 standards, the growth
2 in new home construction completely determines the
3 disproportion of the forecast. So, any anomalies can be
4 traced back to the household forecast, essentially.

5 Overall, though, for the entire State, and these
6 numbers are for 2030, I didn't mention that, the AAPV
7 portion is pretty similar to the previous forecast.

8 COMMISSIONER MCALLISTER: Okay.

9 MR. KONALA: So, I'm actually going to move on
10 to some of the utility forecasts. And I have a lot more
11 data on here than I can go through. But just for
12 completeness, I have lots of tables in here.

13 So, for PG&E, I've provided the baseline
14 forecast. In terms of total energy in 2018, theirs is
15 about 6,400 gigawatt hours' worth of energy generated
16 from behind-the-meter PV. In the mid case, we expect
17 that to go up by about three times, to about 18, 2000.

18 Solar installations are growing at a pretty good
19 rate, although we see faster growth in the commercial
20 sector than the residential sector. As you can see,
21 growth is higher in the early part of the forecast, than
22 the later part of the forecast. That's mainly due to
23 two reasons. One, we have the expiration of the tax
24 credit in 2021, so that's driving some of the adoption
25 early on and it's tapering off later on.

1 But also, in 2020 we have those additions from
2 the Title 24 standards, so that's also bumping up
3 adoptions in 2020, as well.

4 In terms of overall numbers, for the low demand
5 case we see generation reaching up to 21,000 gigawatt
6 hours and in the high demand case as low as 15,000
7 gigawatt hours.

8 And I have a chart here just showing the trends
9 in the different sectors. So, you can see that growth
10 is primarily driven by the residential sector in the
11 early years, but then it's flattening out a little bit,
12 and the commercial sector is what's growing in the later
13 part of the forecast.

14 So, PG&E represents the largest portion of
15 installed capacity in the State, so their numbers are
16 going to kind of match the statewide average. The other
17 utilities, I will be comparing to like PG&E as a proxy
18 for statewide average.

19 So, moving on to Southern California Edison.
20 So, for Southern California Edison, in 2018 we estimate
21 that PV generation was about 4,400 gigawatt hours. By
22 2030, we expect that to grow to about 14,500 gigawatt
23 hours in the mid case, up to 16,900 gigawatt hours in
24 the low case. Just like PG&E and the statewide
25 forecast, the mid case is higher than the previous mid

1 cases. This is primarily driven by higher growth for
2 Edison, both in the residential and the commercial
3 sectors compared to previous forecasts.

4 Overall, compounding the annual growth rate for
5 solar between 2018 and 2030 is about 10 percent. And
6 the midrange is about 9 percent higher than the 2018
7 forecast.

8 Okay. So, now, moving on to San Diego. So, for
9 San Diego, estimated PV generation in 2018 was about
10 1,700 gigawatt hours. We forecast that to go to about
11 4,100 gigawatt hours in the mid case, and as high as
12 4,600 gigawatt hours in the low energy demand case.

13 Now, San Diego has a different curve to it and
14 I'm going to get into that in the next slide. So, one
15 of the trends that becomes evident, when you compare
16 different utilities, is starting at where the baseline
17 penetration rate for PV is, is kind of determining how
18 fast or how slow PV grows. So, Edison had the fastest
19 growth rate in the State over the forecast period, but
20 that's because they had the lowest penetration rate of
21 solar in 2018.

22 San Diego is on the opposite end of the
23 spectrum. They currently had the highest penetration
24 rate of solar compared to any other utility, but they
25 have the slowest growth rates. And that's just because,

1 especially in the low energy demand case, they're kind
2 of saturating the market, especially in residential
3 solar. And since the mid case is an average of the low
4 and high cases for our PV forecast, part of that is
5 being translated into what you see in the mid case,
6 which is shown in this graph.

7 So, in this case, you can see strong growth in
8 the residential sector through 2021, people taking
9 advantage of the tax credit. And then, essentially, a
10 leveling off of growth in the residential sector.

11 But in the commercial sector, you still see
12 growth happening, and that leads to the funky curve from
13 the previous slide.

14 So, okay. Finally, I'm going to move on to the
15 POUs, although we already discussed LADWP. So, in 2018,
16 energy generated from PV was about 486 gigawatt hours.
17 And in the mid case, we forecast that to go to about
18 1,080 gigawatt hours. That's about a 20 percent
19 decrease from the previous forecast. And the vast
20 majority of that decrease does come from how we are
21 modeling AAPV and the effect of that slower growth rate
22 and new household growth.

23 So, if, for the revised forecast we have revised
24 growth in households, then that could go back up. But
25 currently, the difference that we're seeing is in the

1 residential sector for new home construction.

2 So, here's a chart of the sector breakdown for
3 LADWP. We don't really see, unlike the other, the three
4 IOUs, we really don't see PV installations in
5 nonresidential and noncommercial sectors, but the vast
6 majority of the PV installations are in the residential
7 sector. And the growth in households is affecting this,
8 essentially the forecast this time versus last.

9 And last of the big five is SMUD. So, in 2018,
10 SMUD had about 320 gigawatt hours of PV generation. In
11 the mid case, we see that going to about 1,130 gigawatt
12 hours. In the low case, as high as 1,470 gigawatt
13 hours. And SMUD has a fairly high growth rate. Part of
14 that has to do with currently they have rather low PV
15 penetration compared to the IOUs, so they just have more
16 room to grow.

17 And I believe I'm channeling my inner Cary
18 Garcia, but overall SMUD's territory is growing faster
19 economically and population-wise, compared to like the
20 other areas, so that leads to faster growth as well.

21 So, that concludes the planning area forecast.
22 So, I wanted to conclude, briefly by going over the next
23 steps for the PV forecast and for the self-generation
24 forecast. But if you have any questions on what I've
25 presented, feel free, okay.

1 COMMISSIONER MCALLISTER: So, I'm good for now,
2 thanks.

3 MR. KONALA: Okay. We have several updates in
4 mind for the revised forecast and moving forward. The
5 most important part for the 2019 revised forecast is to
6 do an updated energy storage forecast. We did do an
7 update for the preliminary, but we did not change any
8 methodology. For the revised forecast, we hope to come
9 up with methodological changes.

10 Basically, right now, our energy storage
11 forecast does a trend analysis of recent trends and we
12 just project that out to 2030.

13 For the revised forecast, we hope to get
14 feedback from stakeholders, especially in the workshop
15 in late September, that Nick had referenced. And we're
16 looking to get more information on energy storage
17 profiles. And with this information, we are hoping to
18 do modeling changes where we do forecasting based more
19 on like the financial metrics, and not just the trend
20 analysis. But this is ongoing work. So, probably,
21 we'll have a lot more information in that workshop in
22 late September about it.

23 COMMISSIONER MCALLISTER: So, on an hourly
24 front, so I think that's great. I mean, there's a
25 really interesting discussion that, actually, I'm not

1 sure how we get past sort of opinion, without really
2 seeing what the marketplace actually does. But how
3 people actually use these batteries, how they dispatch
4 them. How they -- you know, do they actually follow
5 economic logic or do they, you know, do kind of a, you
6 know, more behind-the-meter just storing their solar
7 when they've got it, or do they arbitrage out there
8 somewhere.

9 So, we need to think about who we want to inform
10 that discussion in the near term to try and anticipate
11 what's going to happen.

12 But on the solar front, what are we doing on the
13 hourly front? You know, obviously, solar's more
14 predictable, but are we looking at how that maps onto
15 the hourlies and, you know, the peak shift and all that?
16 What status is that discussion in or that part of the
17 analysis?

18 MR. KONALA: Okay. So, we have hourly
19 generation profiles. We currently used profiles from
20 E3, which was a confidential study that they did for the
21 CPUC, I believe in like 2013, 2014, based on about five
22 years' of historical generation.

23 COMMISSIONER MCALLISTER: That's the production
24 profiles of PV?

25 MR. KONALA: Yeah.

1 COMMISSIONER MCALLISTER: Okay.

2 MR. KONALA: Yeah. So, we have that
3 information. We incorporate that and we provide a
4 project of historical -- sorry, hourly forecasts. And
5 then, that gets fed into the general California Energy
6 Demand Hourly Model. But the hourly numbers are only
7 incorporated for the IOUs. For the POUs, we just use a
8 peak factor.

9 COMMISSIONER MCALLISTER: Okay.

10 MR. KONALA: So, there's a different methodology
11 depending on whether it's an IOU or a POU.

12 COMMISSIONER MCALLISTER: Okay.

13 MR. KONALA: So, in terms of PV generation
14 profiles, and I have this later in the slide, there --
15 we -- so, the data is a little bit old and it is
16 confidential, so we can't share it out. But we're
17 looking into maybe getting update PV generation
18 profiles. Unfortunately, a lot of the work for the
19 preliminary forecast went into just looking at
20 historical data from that new, 1304-B dataset. So, a
21 lot of the modeling work we wanted to get to on PV
22 generation profiles didn't get done for the preliminary.
23 And there probably isn't enough time to get it done for
24 the revised. So, we're hoping it will be part of the
25 2020 update for the new PV generation profiles.

1 COMMISSIONER MCALLISTER: Yeah, okay. I mean,
2 NREL, I see NREL we've got coming up next. But on a
3 different topic, NREL also has tools to do the modeling,
4 production modeling, you know, based on satellite data
5 and stuff, so it's not based on monitored data. But if
6 -- maybe we could do a project to see whether they're
7 that different. And that could actually save some
8 effort if we could model and be pretty much right on. I
9 don't know, just a suggestion.

10 MR. KONALA: Yeah. The datasets that NREL has,
11 that they use to power their PV Watts application, is
12 one of the thing we're considering for the new PV
13 generation model.

14 COMMISSIONER MCALLISTER: Okay, great. Thanks.

15 MR. KONALA: And then, my final slide, which I'm
16 just going to -- so, an update on the NREL model that
17 we're contracting with NREL to adapt, their DGen model
18 for use, for the State of California. So, that work is
19 ongoing. NREL is going to present the preliminary
20 results today and then, they'll come back in December
21 and present some revised results, as well.

22 But modeling work is going to be ongoing between
23 now and then, and maybe even after the revised forecast.

24 And then, I've presented this slide before, so
25 I'll be short. But, hopefully, our hope is to have

1 staff running this model by the next IEPR forecast in
2 2021. So, with that, that concludes my presentation.
3 And the details about the NREL model, I want to leave it
4 up to Kevin McCabe, of NREL, to describe when he's up
5 here.

6 COMMISSIONER MCALLISTER: Okay. All right.
7 Thanks, Sudhakar.

8 MR. FUGATE: Okay. So, our next presenter is
9 Kevin McCabe, with NREL, to talk about dGen.

10 MR. MCCABE: Good afternoon. My name is Kevin
11 McCabe. I'm an analyst at the National Renewable Energy
12 Laboratory, in Golden, Colorado. Today, I'll be
13 presenting our preliminary results for our rooftop solar
14 forecast and model validation study, for which we've
15 been contracting with the CEC for the past year and a
16 half, or so.

17 Quickly, I'd like to thank members of the dGen
18 team, Paritosh Das, Ben Sigrin, and Trevor Stanley,
19 without whom this work would not have been possible.

20 So, for those unfamiliar, NREL has been
21 contracted by the California Energy Commission to adapt
22 our DER adoption forecast model for the State of
23 California. That model is called the Distributed
24 Generation Market Demand Model, or dGen for short. I'll
25 touch a little bit more about some of the higher level

1 details of the model on the next slide.

2 But to introduce today's talk, I note that we'll
3 be presenting on two distinct aspects of the project to
4 date, namely very new work. The development of a new
5 methodology to calibrate and validate dGen's predictive
6 performance. And this is done by defining a historic
7 period, in this case the years 2008 through 2016, and
8 understanding how dGen would have predicted or, rather,
9 the amount of adoption dGen would have predicted for
10 that backcasted portion of the model.

11 And this gives us the sense of not only the
12 accuracy of those historic periods, but also gives us
13 confidence in the model moving forward in the forecast
14 portion.

15 And speaking of forecasts, that is the second
16 aspect of the results presented today, our preliminary
17 forecast for distributed solar generation in the State.
18 Noting a few updates relative to last year's DAWG
19 meeting, which was kind of the last major iteration of
20 the model, namely we have increase of spatial
21 resolution, not only in the ability to ingest inputs,
22 but also increase spatial resolution of the outputs, as
23 well.

24 We've also been looking into improved resolution
25 of emerging market segments. Think multifamily

1 buildings, renter occupied buildings, anything that's
2 the nontraditional, non-single-family owner-occupied
3 segment. And, of course, we've been incorporating, as
4 they roll out, the net metering 2.0 features throughout
5 the IOUs including, of course, the transition to time-
6 use tariffs. And other features, including non-
7 bypassable charges, interconnection fees, et cetera

8 I mentioned dGen is our adoption forecast model.
9 It is capable of forecasting the adoption of distributed
10 PV or solar, but we also have modules for behind-the-
11 meter storage, wind, and geothermal as well, think
12 geothermal or ground source heat pumps. And this
13 forecasted adoption can be done by region and sector
14 through 2050, though today we'll be looking only through
15 2030.

16 dGen is in the family of agent-based models and
17 is capable of simulating complex, consumer decision
18 making processes. It gets at understanding the
19 behaviors that consumers exhibit and some of the
20 decisions they make when considering adopting
21 distributed generation technologies.

22 dGen also sits on a rich amount of spatial data,
23 which we intersect a number of these spatial layers to
24 better understand when and where adoption occurs in a
25 given region. This graphic on the right gives you a

1 sense of what that might look like. This was from some
2 recent analysis where we were looking at the tradeoff of
3 the economics of a distributed wind versus a distributed
4 solar, or rooftop PV project throughout the State.

5 The panel on the top right shows the solar
6 resource in the State. The panel on the bottom left
7 shows the county level electricity consumption in an
8 annual term. And then, the bottom right panel is a
9 metric we call the solar siting availability. It just
10 gives us a sense of the percentage of rooftops in a
11 given area that are suitable for rooftop solar siting.

12 And, really, all these layers combine and
13 intersect to inform that top left panel which is, in
14 this case, what we call economic potential. I get back
15 to that definition in a few slides. But just, the gist
16 of this is that we have a number of intersecting spatial
17 layers on top of other layers, on top of other data, and
18 all these intersect to give us a sense of results of
19 adoption or potential for the State.

20 And this is important because within the team
21 we're really starting to ask ourselves how accurate is
22 our model? How accurate is any adoption forecast model?
23 And a big motivator for that is cost, naturally.

24 This is some work performed by colleagues at the
25 lab, which showed that the cost of mis-forecasting

1 distributed generation resource can be quite high,
2 though certainly varies greatly with the amount of
3 actual error and the DPV penetration level.

4 Here, this chart is a little busy, but I'll walk
5 through it. Here, on the X-axis we're looking at the
6 systematic error in a 5-year forecast for a given
7 utility or region. The Y-axis shows an increasing level
8 of DPV penetration over a 15-year period as a percentage
9 of total generation. And the V-axis, or what the
10 colored regions are showing, is the change in total
11 present value system cost relative to what a perfect
12 forecast would have been.

13 And so, there's some interesting regions on the
14 graphic here, but perhaps the most critical is in the
15 top left corner, where we see a hypothetical region, a
16 hypothetical utility with an 8.5 percent DPV penetration
17 level that is under forecasting at a 100-percent rate.
18 In this case, we are looking at upwards of \$6.8 million
19 per terawatt hour of electric sales, that is those costs
20 that re incurred due to that mis-forecast.

21 And so, maybe that's not a great example. You
22 would expect that utility, expecting 8.5 percent
23 penetration, would expend a little more effort and cost
24 into their forecast. But, nonetheless, it just
25 illustrates some of the motivators and drivers for

1 understanding DR adoption.

2 And, certainly, we've looked at the literature
3 and tried to better understand these drivers. But a lot
4 of literature base is largely oriented around
5 explanation and not necessarily prediction of the
6 adoption itself.

7 So, that leads us to where we are today. The
8 methodology for adapting our dGen model for the State of
9 California. I mentioned we're starting to look at a
10 backcasted period, starting in 2008 and running through
11 2016 as our historic period. And what we're really
12 attempting to get at is economic calculations and,
13 ultimately, adoption projections for those historic
14 years.

15 And so, the chart on the left gives you a sense
16 of what those economic calculations might look like.
17 This is the model of the payback period. The payback
18 periods are coming out of dGen for that historic period
19 and looking forward to 2025. And from this, you can
20 start to see some of the trends that you might expect,
21 like decreasing solar technology costs over time.
22 Perhaps you can see the effect of the ITC phase out, the
23 effect of net metering 2.0 rollout, et cetera.

24 And this gives us confidence and leads us to the
25 chart on the right, which is what we're trying to match,

1 what we're trying to fit the dGen model to, which is the
2 known annual installed DPV capacity in the State, going
3 as far back as 2000 in this chart but, of course, 2008
4 is the start of our historic period.

5 And so, the effort, the recent effort we've
6 embarked on with the CEC is to try to understand how we
7 can better calibrate the model to match that historic
8 data. And so, to that end, dGen was calibrated with
9 suite of scenarios to better understand the effect of
10 two distinct aspects on the fit to historic data.

11 So, we looked at the effect of the geospatial
12 resolution. We do have county level adoption totals,
13 historic adoption totals. And so, we wanted to look at
14 the effect of keeping, or rather fitting the model using
15 county level data versus aggregating that up, and
16 looking at what the fit would be at the State level.

17 And we also looked at the influence of historic
18 payback periods as well, essentially, the influence of
19 historic economics on the goodness of fit of model to
20 actual data. And so, what we found is that in general
21 the fit to historic adoption data is better when the
22 influence of historic payback periods is ignored.

23 And this is, perhaps, a bit counterintuitive.
24 You would expect economics are, and indeed are, one of
25 the main drivers for adoption of any distributed

1 generation technology. And the other aspect, the effect
2 of geospatial resolution we found to be minimal, though
3 the best fit in this suite of scenarios is looking at
4 county level resolution.

5 And so, the table on the right shows you some of
6 the numbers related to these scenarios that we ran,
7 where indeed the county level resolution, plus the no-
8 payback influence scenario gave us a normalized root
9 mean square error of about 13.7 percent. And so, that
10 corresponds to the orange line there, in the chart on
11 the left.

12 You know, and I should mention this is very new
13 work. We're continuing to refine these methodologies
14 and processes. I mentioned that there is some counter
15 intuitiveness to the fact that our best fit came from a
16 scenario where we are not considering historic
17 economics. As I mentioned, we're continuing to
18 understand this process and potentially refine these
19 results to include -- to improve them in general.

20 And so, what this does is this calibration and
21 validation study gives us confidence, then, moving
22 forward looking at our adoption forecast. Where we are
23 again looking at a suite of scenarios, this time looking
24 forward, to show the sensitivity of projected adoption
25 to certain variables or conditions, including different

1 PV cost schedules, as well as the demand scenarios that
2 the CEC has run in their analysis.

3 So, anchoring our scenario analysis is the mid
4 case. This is, essentially, our central assumptions of
5 things like technology costs, the growth rates for
6 economics and demographics, as well as the growth rate
7 of electricity, retail and wholesale rates that is.

8 And then, surrounding those in the demand
9 scenarios are the high and low demand scenarios, which
10 we've attempted to align, as best as possible, with the
11 CEC high and low demand scenarios. Though, certainly we
12 note that the frameworks of the two different models are
13 quite distinct and, therefore, some of the inputs aren't
14 exact though, as I mentioned, we have attempted to align
15 them as best as possible.

16 Two other scenarios that we're looking at as
17 well, on top of these demand scenarios, are looking at
18 the effect of differing PV cost schedules over time.
19 And these are the high and low PV cost scenarios that
20 you see here. And before I move on from this slide, I
21 note that a lot of our data and projections of things
22 like costs and rates come from NREL's annual technology
23 baseline, or ATB effort. There's some details on the
24 site there, atb.nrel.gov, and I'd be happy to answer
25 more questions at any time. But this just gives us a

1 sense of what technology costs look like into the
2 future, under different scenarios and, by extension,
3 what the retail and wholesale electricity rates look
4 like for that given mix of generation technologies.

5 And so, here are the preliminary results for the
6 adoption forecast, showing the sensitivity to those
7 scenarios that I mentioned. We found that the
8 sensitivity of adoption to the demand scenarios is
9 actually quite modest. Noting that the range between
10 the high and low scenarios in 2030 is only about 3.1
11 gigawatts AC.

12 And we're starting to understand how these
13 demand scenarios are being internalized in the model.
14 And what we're starting to understand is that the
15 influence of electricity rate growth is actually much
16 greater than that of the load growth. And part of that
17 is in part due to the way that dGen calculates system
18 sizes.

19 dGen takes, as the max system size that a
20 consumer can size their system as the minimum between
21 offsetting 100 percent of their annual electricity load,
22 the minimum between that and developing -- or, rather,
23 citing solar panels on their total developable roof
24 area. And so, you can expect in a scenario where load
25 is decreasing over time, that max PV size is also

1 decrease and then, by extension the selected, the
2 ultimate selected system size would also decrease.

3 And so, we're starting to understand how these
4 scenarios are acting within the model, but that's what
5 we believe to be a major driver is the electricity rate
6 growth.

7 COMMISSIONER MCALLISTER: So, let me just make
8 sure I got that clear. So, in a case where you've got a
9 roof that's big, like larger than an F or a net zero
10 kind of scenario, you're assuming that somebody -- that,
11 basically, the size would be equivalent to net zero?

12 MR. MCCABE: I think that, considering net zero
13 effects may be going a little bit too far.

14 COMMISSIONER MCALLISTER: Did you say 80
15 percent, or I'm sorry.

16 MR. MCCABE: So, we are looking at the minimum
17 between the maximum PV size. This is not the size that
18 is actually selected.

19 COMMISSIONER MCALLISTER: Yeah.

20 MR. MCCABE: The maximum size that a consumer
21 can select is either covering 100 percent of the
22 developable roof area, for their roof --

23 COMMISSIONER MCALLISTER: Yeah.

24 MR. MCCABE: -- or offsetting 100 percent of
25 their annual load.

1 COMMISSIONER MCALLISTER: Oh, okay. So, you're
2 not assuming that everybody who can offsets 100 percent
3 of the load.

4 MR. MCCABE: Correct.

5 COMMISSIONER MCALLISTER: You're just saying
6 that that's the maximum.

7 MR. MCCABE: That's correct.

8 COMMISSIONER MCALLISTER: Okay. Okay, I missed
9 that part. So, great, thanks a lot.

10 MR. MCCABE: And that system size selection
11 process then looks through between zero and that max
12 size --

13 COMMISSIONER MCALLISTER: Oh, okay, gotcha.

14 MR. MCCABE: -- and selects the one that has the
15 best economics.

16 COMMISSIONER MCALLISTER: I gotcha. Thanks for
17 that.

18 MR. MCCABE: Sure. So, that was kind of a
19 discussion around the high and low demand scenarios.

20 The PV price scenarios, we note that although
21 California has been a pretty mature market for solar
22 throughout the years, PV prices continue to show a
23 pretty significant effect on projected adoption.

24 In this case, the range between the high and low
25 PV cost scenarios in 2030 is more than double what we

1 saw in the high and low demand scenarios. Specifically,
2 7.6 gigawatts AC in 2030. Although, I should note that
3 the inputs, the actual PV installation costs for those
4 two scenarios are quite distinct as well, where we're
5 looking in the high PV scenario at an installed cost of
6 \$3 per watt. In the residential sector versus in the
7 low PV scenario about \$.50 a watt. So, you can start to
8 see and expect that large ranges in the inputs could
9 result in larger ranges in the outputs, naturally.

10 There's a lot more numbers and results by
11 planning area, but this is a single slide that starts to
12 get at these results. And so, what we note is that,
13 perhaps unsurprisingly, the major IOUs will continue to
14 lead the way with adoption.

15 We are estimating in the PG&E and Edison
16 planning areas about 10.7 gigawatts AC of cumulative
17 adoption by 2030. And that's followed up by San Diego
18 at 2.8, SMUD at 1.5, LADWP at 1.4, and all other
19 planning areas at 0.6 in 2030, in the mid case scenario.

20 You know, and despite the sheer size advantage,
21 if you will, of PG&E and Edison territory, we do note
22 that economics at the granular level, when you start to
23 dig into the granular results things like full retail
24 net metering for the non-IOUs, other utility-specific
25 incentives really do show up in those economics. And

1 so, statewide, we're looking at quite a bit more --
2 quite a bit of favorability for adopting PV throughout
3 the years.

4 I mentioned that the start that we're starting
5 to look into some of the nontraditional market segments.
6 Traditional being just the single-family, owner-occupied
7 segment. And new datasets that have been developed at
8 the lab have enabled some preliminary analysis of these
9 markets.

10 In particular, the replica dataset, on the right
11 there, shows -- or, rather gives us census tract level
12 data for things like solar technical potential. Rooftop
13 area, for example, we use Lidar data to estimate rooftop
14 area. We have census tract level data for things like
15 building counts, customer counts, et cetera.

16 And so, what this really, finely resolved
17 dataset allows us to do is understand what these
18 emerging market segments might look like. And though,
19 you know, moving past some of the pure economic
20 calculations into what is ultimately adopted certainly
21 introduces some uncertainty.

22 And so, what we've done here is instead of
23 report adopted totals for these emerging segments, what
24 we're doing is looking at a metric that we call economic
25 potential. And this is defined as the amount of PV

1 capacity that exceeds a given rate of return. In
2 essence, PV systems that exhibit a positive net present
3 value. There are a number of financial inputs into the
4 model, and so these are all dependent on those as well.

5 But what we note is that the amount of economic
6 potential in the nontraditional market segments could
7 add an estimated 45 gigawatts AC of potential statewide,
8 in 2030. And this is on top of nearly 80 gigawatts of
9 potential in the traditional single-family, owner-
10 occupied, and nonresidential sectors.

11 And so, certainly, there's a lot more work to be
12 done to understand what adoption actually looks like for
13 these emerging segments. Things like ownership issues,
14 HOA considerations. All of these things need to be
15 taken into account before we have a little bit more
16 confidence in understanding what adoption looks like.

17 But in a pure economic sense, there is quite a
18 bit of promise for these emerging segments.

19 I will wrap up. I have one more slide after
20 this, but this is a look at some of the geospatial
21 trends of adoption. This is looking at our mid case
22 scenario in 2030. And this kind of harkens back to what
23 I was discussing in the beginning, where a number of
24 multiple spatial layers start to intersect and to inform
25 where and when adoption occurs in the State.

1 In this case there's, perhaps, no surprise that
2 many of the Southern California counties are leading the
3 way at the county level resolution. We're starting to
4 see adoption follow trends of strong solar resource, not
5 surprisingly. Areas of high load, not surprisingly.
6 So, starting to intersect many of these different layers
7 and inputs result in something like this.

8 An so, here we see Los Angeles, San Diego,
9 Riverside, Orange, and San Bernardino Counties rounding
10 out the top five by installed capacity.

11 I'll quickly wrap up here, just to kind of
12 conclude some of the discussion I just gave. So, the
13 new effort to calibrate and validate the model has
14 really illustrated some of the major influences on how
15 well we can fit model data to known historic data.

16 And for this preliminary study, we're looking at
17 two distinct aspects, namely the effect of historic
18 payback periods, as well as the geospatial resolution of
19 known historic adoption totals versus modeled. And
20 we're starting to better understand other datasets,
21 other attributes of the model that can potentially
22 improve the fit.

23 And so, this is very new work and we're excited
24 to see it through to potentially see better fits of
25 model to historic data.

1 We found, looking at the forecast data, that
2 there is pretty modest sensitivity of adoption to the
3 demand scenarios, but a much more acute sensitivity to
4 PV prices. Perhaps, unsurprisingly, by planning area we
5 note that the major IOUs are projected to lead adoption
6 though, certainly, economics for the non-IOUs are quite
7 favorable, still.

8 And then, finally, looking at emerging markets,
9 things like non-single-family, owner-occupied market
10 segments do show quite a bit of promise, though we note
11 that further data and analysis tools are certainly
12 necessary to be able to model these segments more
13 accurately.

14 So, with that, I will wrap up and I'm happy to
15 take any questions.

16 COMMISSIONER MCALLISTER: Yeah, I have a couple
17 questions, actually. So, are you looking at
18 incorporating storage into this, like sort of solar plus
19 storage and how that impacts the economics and,
20 therefore, the adoption?

21 MR. MCCABE: Yeah, that is certainly a part of
22 this partnership. To date, we have not run any solar
23 plus storage modeling scenarios, though dGen is capable
24 of doing so. We're kind of -- outside of this project,
25 we're starting to look at overhauling the major module,

1 which calculates bills, and incorporates technologies
2 like solar and storage together.

3 COMMISSIONER MCALLISTER: Uh-hum.

4 MR. MCCABE: And so, we're starting to get a
5 little bit more confidence in being able to present
6 those results. Though, you mentioned in Sudhakar's
7 presentation that there are some questions as to whether
8 the strategy should be economic dispatch versus
9 arbitrage.

10 COMMISSIONER MCALLISTER: Yeah.

11 MR. MCCABE: So, we, as well, are starting to
12 understand how best to report adoption estimates for
13 behind-the-meter storage.

14 COMMISSIONER MCALLISTER: Yeah, that's great.
15 And we're having that conversation in the context of the
16 building standards themselves, right, so outside of the
17 forecast, in a different arena. But, you know, how we
18 can justify including -- or, how we include storage in
19 the building standards really depends on what the
20 options are for people to use it and dispatch it.

21 MR. MCCABE: Certainly.

22 COMMISSIONER MCALLISTER: You know, developers
23 aren't going to put it in a new home, if people don't
24 want it or if we limit how they can use it.

25 And so, the second question, are you looking at

1 -- well, sort of related to the first. Are you looking
2 at production curves, you know, sort of hourly or, you
3 know, interval capacity shapes or production shapes for
4 the PV.

5 MR. MCCABE: Yes. Right, yeah, we do. So, as
6 Sudhakar mentioned, we have been provided with
7 generation, 8760s of generation by the IOUs and --
8 mostly the IOUs. But NREL also has done quite a bit of
9 research into typical meteorological year data --

10 COMMISSIONER MCALLISTER: Yeah.

11 MR. MCCABE: -- MY data. We've, across the lab,
12 have been overhauling to TMY3 recently. We've also
13 started looking into the benefits and challenges of
14 using actual meteorological year data. There's,
15 perhaps, some benefit to using that actual data to
16 better understand weather effects, et cetera.

17 COMMISSIONER MCALLISTER: Yeah.

18 MR. MCCABE: So, when we use that TMY3 data, we
19 have a lot more measurements, a number of weather
20 stations throughout the State of California and hundreds
21 throughout the U.S. that we can potentially use to model
22 or, rather, give generation, hourly generation profiles.

23 COMMISSIONER MCALLISTER: Is NREL putting any
24 emphasis on SAM, anymore?

25 MR. MCCABE: Oh, yeah, a ton.

1 COMMISSIONER MCALLISTER: Okay.

2 MR. MCCABE: The System Advisor Model?

3 COMMISSIONER MCALLISTER: Yeah, yeah, because
4 that seems like a perfect model to generate some of
5 these curves, and then calibrate those against reality,
6 and then see if you can just use SAM going forward.

7 MR. MCCABE: Yeah, SAM has been under some
8 pretty major development in the last years. It's open
9 source, it's capable of simulating a number of different
10 generation technologies. That's actually, when I
11 mentioned that we're looking to overhaul some of our
12 internal calculations, the SAM module for bill
13 calculating is something that we're hoping to include
14 because --

15 COMMISSIONER MCALLISTER: That would be great.

16 MR. MCCABE: -- they have a much better
17 representation of storage than --

18 COMMISSIONER MCALLISTER: That would be great.

19 MR. MCCABE: Yeah, so stay tuned.

20 COMMISSIONER MCALLISTER: Yeah, okay. I'm sure
21 we'd love to collaborate on that.

22 MR. MCCABE: Great.

23 COMMISSIONER MCALLISTER: Yeah. Thanks for your
24 presentation.

25 MR. MCCABE: Thank you.

1 COMMISSIONER MCALLISTER: Yeah, good. All
2 right, thanks.

3 MR. FUGATE: So, next up is Chris Kavalec, who's
4 going to get us back on track with a 5-minute
5 presentation on all of his hourly work.

6 MR. KAVALEC: Good afternoon. I am Chris
7 Kavalec from the Energy Assessments Division. And I'm
8 going to talk for five minutes or maybe a little longer
9 about our hourly load forecasts, provide some results
10 for peak projections for the IOUs. And the IOUs, if
11 they want to have specific comments about these peak
12 forecasts, they can fold that in with the comments they
13 provide when Cary does his planning area presentations a
14 little later. And then, I'm going to talk a little bit
15 about next steps.

16 Okay, the reason that we are doing hourly load
17 modeling, which we started to do about three years ago,
18 is that the darn peak hours won't stay put anymore
19 because of all the demand modifiers, particularly PV.
20 And so, therefore, to properly model peak and capture
21 this so-called peak shift that is now happening, one
22 needs an hourly analysis to account for it properly.

23 Also, since we're doing hourly load forecasts,
24 we can now provide monthly peaks at the TAC level,
25 transmission access charge level, for resource

1 adequately purposes for their year-ahead analysis, to be
2 used as a benchmark as they do their individual LSE
3 year-ahead projections.

4 And also, the California ISO uses our hourly
5 results in their flexibility studies, looking at 3-hour
6 ramp ups, 3-hour ramps over the course of a year.

7 I won't give a lot of technical details. I'll
8 just briefly review what this model is all about. What
9 we're estimating with this hourly load model is what we
10 call consumption load ratios, meaning hourly consumption
11 divided by the average of hourly consumption over the
12 course of a year.

13 Now, I have consumption in quotes there because
14 it's defined a little bit differently than we typically
15 define consumption. What it is, in this context, is
16 sales, plus line losses, plus PV, plus avoided losses
17 from PV. And it does not include non-PV self-gen.

18 It's set up this way because our model is based
19 on the EMS data from California ISO, which includes
20 hourly data, which includes losses.

21 So, these consumption load ratios are specified
22 as a function of weather and calendar variables. And
23 then, once these are estimated, we take average hourly
24 consumption, as I've defined it, from the traditional
25 IEPR long term forecast for each year, apply it to those

1 load ratios and that gives us hourly, what we call
2 unadjusted consumption for each hour and each year.

3 Okay. We then adjust those unadjusted
4 consumption numbers by incorporating hourly EV load,
5 hourly climate change impacts, residential TOU, and a
6 couple other minor consumption adjustments for a couple
7 of the smaller LSEs.

8 And then, we subtract off hourly PV generation
9 to give us baseline hourly sales forecasts. And that
10 should say baseline hourly sales plus losses forecasts,
11 the way we've defined our metrics here.

12 And the maximum of those baseline hourly sales
13 forecasts is what we call the net peak for the year, or
14 the net baseline peak for the year.

15 We are currently doing our hourly load forecasts
16 at the IOU TAC level, the three IOU TACs that we're
17 familiar with, transmission access charge areas. And
18 then, to round out CAISO, we also do a separate model
19 for Valley Electric. A small area, but it's considered
20 a TAC and it's included in CAISO.

21 Then, when we get to our revised forecast, later
22 in the year, we will also be incorporating hourly AAEE,
23 as Ingrid mentioned earlier, to give us our managed
24 sales forecasts by hour -- sales plus losses forecast by
25 hour. And from that, get managed peaks for planning

1 purposes.

2 Some updates versus the last time we did an
3 hourly load forecast for 2018. This time, we did a
4 separate estimation of pumping loads, using a fairly
5 simple regression model, where for each hour we specify
6 the amount of pumping by month, and day of the --
7 weekday versus weekends, and holidays.

8 And for Northern California, this means
9 Department of Water Resources. And for Southern
10 California, this means Department of Water Resources and
11 the Metropolitan Water District.

12 The reason that we wanted to estimate these
13 separately is that pulling out the pumping loads from
14 the rest of the load just, hopefully, gives you more
15 precise estimates of the impact of weather and calendars
16 on the rest of the load, since pumping load is a little
17 bit different, obviously, than the rest of the load.

18 We wanted to model DWR and MWD separately for
19 Southern California. But the data we have now for MWD
20 isn't very good. So, what we did was to model DWR and
21 MWD together, using the EMS pumping loads provided to us
22 from California ISO, which is a combination of the two.

23 We have new hourly EV loads and load shapes, a
24 new PV forecast, as Sudhakar mentioned earlier. And,
25 when we get to the revised forecast, we'll have new AAEE

1 numbers.

2 A little bit about the hourly EV loads and load
3 shapes. For the last couple of forecasts, we used
4 hourly EV profiles from Lawrence Berkeley, based on a
5 household travel survey.

6 For this forecast, we are using load shapes
7 developed by ADM Consulting as part of our load shapes
8 and HELM project, that I'll talk about a little bit
9 more, later. And these profiles are based on actual
10 vehicle charging data from ChargePoint and from Joint
11 IOU EV Load Research reports.

12 And here's a typical load shape that we can
13 compare to what we had in the previous two forecasts.
14 This is for Edison, for a June weekday in 2030, but it's
15 fairly typical of the shape that you'll see for the
16 other IOUs, and different times of the year.

17 So, we have, in dark blue, the new shape from
18 ADM and in red, the shape that we used in the last
19 couple forecasts from Lawrence Berkeley. And you can
20 see the big difference there is that, according to
21 ChargePoint, there's more charging in the middle of the
22 day, significantly more.

23 Oh, I should mention that what this is showing
24 is the percentage of load by hour, the percentage of
25 daily load by hour. That's what's on the vertical

1 access there.

2 And then, the other big difference is that when
3 we get to the --

4 COMMISSIONER MCALLISTER: So, is that an 8
5 percent or a .08 percent?

6 MR. KAVALEC: Oh, yeah, it's -- okay, proportion
7 of load, daily load by hour.

8 COMMISSIONER MCALLISTER: Oh, okay. Okay, so
9 it's --

10 MR. KAVALEC: Yeah. Sorry.

11 COMMISSIONER MCALLISTER: Okay, got it.

12 MR. KAVALEC: So, when we get to the late
13 afternoon/evening hours, where we are under residential
14 -- the residential TOU pricing regime, you see a much
15 bigger drop off in the new load shape versus what LBNL
16 was estimating, previously.

17 And this means that the elasticity of demand
18 relative to the peak, non-peak TOU price, or elasticity,
19 or sensitivity is much greater in the ADM load shape
20 analysis.

21 Okay, some results. First, for California ISO,
22 which is the sum of the individual IOU TACs, plus Valley
23 Electric. You can see at the beginning of the forecast
24 period that drop off. And that reflects the consumption
25 and sales drop off from 2018 to 2019, that Cary

1 mentioned earlier. And that comes about because of the
2 weather adjustment, going from the historical to the
3 forecast period.

4 And then, the big lump of additional efficiency
5 program savings in 2019. And also, for PG&E,
6 specifically, we assumed relatively heavy amount of
7 rainfall in 2019, based on the early months of 2019,
8 which meant a lot less groundwater pumping. So, the
9 drop off in consumption and in net peak is greater for
10 PG&E compared to the other IOUs for that reason.

11 Okay. And that's an assumption, that amount of
12 heavy rainfall year that we'll revisit for the revised
13 forecast.

14 Okay. A drop off at the beginning of the
15 forecast period. And then, you see in the mid and low
16 cases, so the red is the 2018 mid forecast, the high,
17 mid and low are green, dark blue, and purple,
18 respectively.

19 In 2020 to 2021, in the mid and the low cases,
20 you see another little drop off there for CAISO. And
21 that's happening -- that comes from PG&E, and I'll talk
22 about that when we get to PG&E in a minute.

23 After that point, after 2020, a little bit less
24 growth in the peak compared to what we had in 2018,
25 comparing the two mid cases. And that's because of the

1 additional standards and a little bit more PV this time.

2 This graph is meant to show the impact of
3 accounting for the peak shift, which I mentioned
4 earlier, our peak hours are shifting to later in the day
5 mainly because of PV.

6 So, the red line there, at the top, is our
7 consumption, peak consumption as consumption defined as
8 I did it earlier. And then, subtracting off PV from
9 that red line, we go down to our net peak, which is
10 given by the green line. Accounting for the change.
11 potential change in peak hour, as we do that.

12 Now, had we not accounted for the change in peak
13 hour and assumed that the peak was happening at the same
14 hour as the consumption peak, the red line, we'd go all
15 the way down to the blue line and have a much lower
16 peak. So, that by 2030, for CAISO, we have a peak shift
17 impact of over 6,000 megawatts. So, that shows how
18 important it is to account for peak shift. We would be
19 underestimating or under-forecasting the CAISO peaks by
20 around 6,000 megawatts by 2030.

21 This is another way of showing the same thing,
22 the peak shift. A little bit of a messy graph here.
23 But this is attempting to show the impact of all the
24 individual demand modifiers that are part of the hourly
25 load model. So, starting with the red line, the bottom

1 line in that group of lines there. that's the unadjusted
2 consumption that I mentioned earlier.

3 We incorporate electric vehicles, pumping,
4 residential TOU, climate change impacts, and we end up
5 at the yellow line there, at the top. So, that shows a
6 consumption peak of around 56,600 megawatts.

7 Then, we subtract off our PV impacts by hour,
8 for that peak day, and that gets us down to the black
9 line. Again, if we assumed that the peak hour did not
10 change and kept the same peak hour as we assume for
11 consumption, we drop all the way down to 43,000
12 megawatts.

13 However, you can see that the peak hour for that
14 black curve or the peak for that black curve is all the
15 way -- the right there, is all the way up over 49,000
16 megawatts.

17 Okay. So, again, accounting for the peak shift
18 means your peak is about 6,000 megawatts higher than if
19 you didn't account for the peak shift.

20 I mentioned this hourly load model being used
21 for -- to develop monthly peaks for resource adequacy,
22 year-ahead analysis. So, looking at 2021 here, the
23 baseline that peaks by month for CAISO, for the mid
24 case, and red is the forecast from 2018, and in dark
25 blue is the new forecast by month. And, not

1 surprisingly, the new forecast by month is a little bit
2 lower because of lower consumption and lower peaks, as
3 we saw earlier in the graphs. And you can see that the
4 gap between the red and the blue is a little bit higher
5 in the warm months because of the additional PV. PV
6 having more of an impact during the warmer months.

7 And I should say, again, this is not the end of
8 the story because these two graphs, like the other
9 results we've shown today, do not incorporate AAEE.

10 Okay, PG&E. Again, the drop off in consumption,
11 which is from 2018 to 2019, which is higher than the
12 other IOUs because of the assumed reduction in
13 groundwater pumping.

14 And then, I mentioned for CAISO you see a drop
15 off in 2020 to 2021. That's coming from PG&E in the mid
16 and the low cases. And what's happening there is we
17 have a big jump in PV adoptions in that year. And that
18 happens to be the year before -- or, the last year
19 before the tax incentives, the tax credits end for PV.

20 And then, after that, more steady peak growth as
21 the rate of PV adoption falls below what it was in the
22 earlier years. A little bit less growth comparing the
23 two mid cases in red and in dark blue for the new
24 forecast. A little bit less growth, again because of
25 the impact of additional standards and a little bit more

1 PV.

2 COMMISSIONER MCALLISTER: Can you comment about
3 sort of what the end state of where the peak ends up?
4 You know, the peak can't get pushed back by solar
5 forever, right? And we've sort of been inching it 15
6 minutes here, you know, and an hour there back into the
7 evening. You know, where does it settle, do you think,
8 in terms of the end state?

9 MR. KAVALEC: Well, it depends on what time of
10 the year the peak happens.

11 COMMISSIONER MCALLISTER: Uh-hum.

12 MR. KAVALEC: But if it's September, which is
13 fairly common for -- recently, for CAISO, as well as for
14 Southern California, by the time you get to 8 to 9 in
15 the evening, you have almost no PV generation.

16 COMMISSIONER MCALLISTER: Yeah.

17 MR. KAVALEC: So, that's where the peak shift
18 basically is going to have to end, at basically 7 to 8.
19 So, your peak could move to 7 to 8 p.m., but beyond that
20 you have no more, or a trivial amount of additional PV,
21 so you don't get any more peak shifts beyond that time.

22 COMMISSIONER MCALLISTER: Right, so that makes
23 sense. I guess, as we -- you know, the next step is to
24 say, okay, well, how do we deal with the ramp leading up
25 to that peak, and in terms of just calculating scenarios

1 around storage, around load shifting, demand
2 flexibility? It seems like we need to start putting
3 some numbers to that. I mean, I'm not saying maybe
4 formally in the 2019 forecast, but probably some
5 strategizing about how we're going to analytically do
6 that, if you guys aren't already doing that. I don't
7 know.

8 MR. KAVALEC: And for PG&E and San Diego, we
9 seem to be pretty close to that limit by the end of the
10 forecast period.

11 COMMISSIONER MCALLISTER: Uh-hum.

12 MR. KAVALEC: It's moved to 7 to 8 p.m. Well,
13 again, it depends on the time of the year and what
14 scenario that you're looking at.

15 And with Edison, which I'll talk about in a
16 minute, which is not quite as far, so it still has a
17 little bit more peak shifting that can happen. At
18 least, according to our forecast by 2030.

19 COMMISSIONER MCALLISTER: Okay, thanks.

20 MR. KAVALEC: Again, looking at the peak shift
21 impact, the net peak is in green. The peak shift
22 impact, shown by the difference between green and dark
23 blue for PG&E, which reaches around 2,800 megawatts by
24 the end of the forecast period.

25 And the other day, we were comparing our peak

1 forecasts with those developed by the PG&E staff, and
2 their growth rate for their net peak is much lower.
3 They have, basically, a flat peak forecast. But they do
4 consider the peak shift and the peak shift impacts.
5 They do, do an hourly analysis.

6 So, the question was, maybe their peak shift
7 impact is not as high as what we're assuming. So, we
8 asked them to look into that and to see if that explains
9 the difference. And if it does, then we need to talk
10 maybe a little bit more about our respective hourly
11 methodologies to see what is different.

12 Again, showing the load modifiers, consumption
13 peak, 25,200. If we didn't consider the peak shift, all
14 the way down to 19,000. Considering the peak shift,
15 we're up to 21,800 for our net peak.

16 For Edison, again not as much of a drop off at
17 the beginning of the forecast period. We don't have
18 that groundwater issue and the weather adjustment is not
19 as large as for PG&E.

20 2020 to 2021, we do have a little spurt in PV,
21 but not as much as for PG&E, so the line's just flat and
22 they don't decrease from 2020 to 2021, like for
23 PG&E.

24 And then, beyond that, like PG&E, a little bit less
25 growth because of additional committed standards and a

1 little bit more PV compared to last time. And comparing
2 the two mid cases, red and dark blue.

3 We've found this phenomenon in the last two
4 forecasts, in our hourly analysis, and that is that the
5 peak shift seems to be a lot lower for Edison than for
6 PG&E. You see the peak shift impact is only about 500
7 megawatts there by the end of the forecast period,
8 compared to 2,800 for PG&E. And I'll talk about the
9 reasons for that in a minute.

10 Looking at the load modifiers, consumption peak
11 28,500, drop down at the same hour to 23,500 when you
12 include PV. Peak shift brings us up to 24,040.

13 So, why do we have a big difference between
14 Edison and PG&E? First off, PG&E has a lot more PV
15 relative to the size of its load, so you have less
16 ammunition for a peak shift.

17 And the other thing is that PG&E loads seem to
18 stay high later, farther out into the afternoon and
19 evening.

20 So, this graph here is showing the percentage of
21 the peak load by hour. And this time, I do have actual
22 percentages, not proportions. So, you can see Edison
23 peaking around 2, 3 o'clock there. And then, dropping
24 off more quickly than PG&E, in red.

25 So, basically, what's going on here, according

1 to my hypothesis, is that when you start losing PV in
2 the late afternoon and evening, when it starts to drop
3 off quickly, for PG&E the total load stays high. So,
4 that means the utility, itself, has to serve more of
5 that load and that means more of a peak shift.

6 For Edison, in the late afternoon as the PV
7 starts dropping off quickly, the load also starts
8 dropping off quickly and, therefore, you have less load
9 having to be served by the utility, less of a peak
10 shift.

11 So, it's those two reasons. We've talked to
12 Edison a couple of times about this and discussed this
13 difference. But Edison is not entirely convinced and
14 would like to discuss this further, which we're happy to
15 do. And that will happen shortly after the workshop.

16 The other thing that Edison mentioned is they
17 think the elasticity of the residential -- or, the
18 impact of residential TOU on electric vehicle load
19 shapes is too high. There shouldn't be as much of a
20 drop off. And they've done some work and gotten some
21 different results for EV load shapes and we're going to
22 talk about that as well, shortly.

23 Finally, San Diego. The drop off from 2018 to
24 2019 is coming mainly from the weather adjustment, but
25 we also have the additional lump of 2019 efficiency

1 program savings. Then after that, again, a slightly
2 less growth because of the committed standards and
3 slightly more PV.

4 Peak shift impact of about 800 megawatts by the
5 end of the forecast period. Shown a different way, peak
6 shift's going from 3,800 to a little bit over 4,600
7 megawatts for the mid case in 2030.

8 In case you're interested, this shows the
9 simulation of pumping loads for Northern California,
10 meaning DWR. And it's similar, the same things are
11 going on in Southern California, so I'm just showing one
12 here, one example.

13 So, I'm showing pumping loads, modeled,
14 simulated pumping loads in a winter month and a summer
15 month, January and July, and then for weekday and
16 weekend.

17 So, you'll immediately notice that as the DWR
18 attempts to accommodate overall load, they're pumping
19 more on the weekends versus the weekday. And they're
20 pumping more in July, not surprisingly, compared to
21 January. Except during the -- you'll see the July
22 curves, the green and the purple, they drop off pretty
23 dramatically as we get toward the peak hours in the
24 afternoon and evening. And gain, that's DWR
25 accommodating the rest of the loads.

1 And the same thing happens in January, although
2 at a different hour. Our peaks are happening in the
3 late evening, mainly because of lighting and some
4 heating. But again, DWR is accommodating that drop off
5 by reducing their -- or, accommodating the peak loads
6 for January by dropping off pumping during those hours.

7 Next steps for the revised forecast. New AAEE,
8 as we've mentioned ad nauseum today. We will,
9 hopefully, have reasonable storage charge discharge
10 profiles, although those will have to come with the
11 caveats that the Commissioner mentioned
12 earlier.

13 We adjust our peak totals by accounting for a little
14 bit of load-modifying DR. It's not very -- it's DR that
15 we agreed with CPUC should be handled on the demand
16 side. The rest of the DR is handled on the supply side.
17 So, it includes like peak pricing, permanent load
18 shifting, TOU, et cetera.

19 We have a little bit of that, that we get from
20 the IOU DR filings that they do every April. And so, we
21 adjust our peak amount by the small amount of LMDR. It
22 amounts to, you know, a couple hundred megawatts for
23 CAISO, as a whole. But it is a pain to have to post
24 process that and say here's our peak, however, you have
25 to adjust it to account for load-modifying DR.

1 So, fortunately, there is, apparently, enough
2 information to be modeled in 8760 for load-modifying DR,
3 so we will attempt to do that.

4 For the revised forecast, we will have updated
5 residential TOU.

6 I mentioned climate change, earlier, as one of
7 the hourly demand modifiers. So, what I did the last
8 forecast, in this preliminary forecast was to take our
9 annual climate change impacts and annual peak climate
10 change impact that Cary discussed earlier, and
11 distribute those impacts over the hours in a given year
12 by, basically, assigning more climate change impacts to
13 the higher load days in the summer, when it's hotter.
14 And, also, the highest decreases coming during the
15 winter months to the winter loads that were highest.

16 Okay. So, basically, I distributed the climate
17 change impacts according to the size of the load, taking
18 into account winter and summer. That's a fairly crude
19 way to do it and we would like to find a more refined
20 way to do this going forward.

21 Fortunately, Scripps was able to develop hourly
22 temperature projections going out 50 years, consistent
23 with the scenarios that they're already providing us,
24 from which we develop our annual climate change impact.

25 So, that means that for the revised forecast we

1 will attempt to integrate their hourly temperature
2 projections into the hourly load model, so that we can
3 have a better, more defensible set of 8760 climate
4 change impacts going forward.

5 The last thing is integrating this with our
6 traditional peak model, which we call HELM, hourly
7 electricity load model, a new version of it, so that's
8 why the 2.0 is there. That new version is the new
9 platform that ADM put together, together with all their
10 new load shapes that we talked about earlier.

11 So, we have these two methodologies that are
12 designed to do the same thing, develop an 8760. So, the
13 question is how do we integrate the two. When do we use
14 one versus another.

15 So, just a little bit about HELM. It's a fairly
16 simple methodology. We're taking annual consumption by
17 end use and building type for the residential and
18 commercial sector from our sector models. And for
19 different NAICS groupings for the remaining sectors.
20 For example, chemical industries is one NAICS grouping.

21 And these load shapes are applied in HELM, and
22 are applied to these annual loads. And then, we
23 aggregate everything up and from that we develop peak
24 load for each year. And then, we adjust that by the
25 amount of self-generation and we get net peaks.

1 So, we've traditionally used that to do our
2 peaks. And the load shapes are very antiquated. They
3 came from the 90s and early 2000s. And so, we enlisted
4 ADM to develop a new platform and update all our load
5 shapes. And that's what they've done. And the HELM
6 2.0, the new version, also adds loads shapes for
7 efficiency, generation profiles for PV, electric vehicle
8 charging profiles, as we've discussed with the
9 unfortunate name of EVIL sub-model. And then, this is
10 all done at the forecasting level.

11 And as I said, this is a nice -- we now have a
12 nice user, hopefully, user-friendly platform for HELM
13 2.0.

14 And here are some of the sources. And two
15 points I want to make here. These different sources
16 serve as a starting point for developing the individual
17 end use building type or NAICS grouping load shapes.
18 And then, these load -- preliminary load shapes are
19 tuned to actual IOU interval meter data. So, that just
20 means, basically, you take a specific building type, for
21 the interval meter data you add up all the loads, hourly
22 loads for the individual end uses associated with that
23 building type, see how they match up. Make adjustments
24 if there's a big difference between the two. So, it's
25 basically a way of calibrating the load shapes.

1 Chargepoint date, as I mentioned, CSI data, as
2 well as other data for PV.

3 And also, as I alluded to earlier, we think of
4 this as a starting point. There are going to be
5 continual new sources of load shaping formation. Meter
6 data, studies like the Commissioner mentioned earlier,
7 being done by PG&E. So, we have a starting point and as
8 new information, data, and studies become available, we
9 will do our best to update the appropriate load shapes
10 based on that information.

11 And here, if you're interested in looking at the
12 load shapes report, we have it posted. It explains the
13 methodology, shows a whole bunch of different load
14 shapes and compares them to what we had in the old HELM
15 model and so on.

16 So, how do we integrate the two? Well, ideally,
17 HELM, this new version of HELM, will provide a
18 reasonable set of 8760 hourly load forecasts for each
19 year. If this is the case, then there are more
20 aggregate hourly load model, the econometric hourly load
21 model would be used as a check, and maybe for some
22 regional studies for regions not covered in HELM 2.0.

23 The reason I say ideally is because of HELM
24 performs to our satisfaction at the 8760 level, then we
25 will have not only total hourly load forecasts, but we

1 can break that down into the different sectors, and even
2 different end uses.

3 However, my experience has been that it's very
4 difficult to develop a model, a bottoms up model to
5 properly characterize 8760 hourly loads. And the reason
6 for that is that at the hourly level, as you get more
7 and more disaggregate, there's just more and more noise.
8 So, when you're trying to match historical data or make
9 the output look like historical data, it gets very
10 difficult to do, the more disaggregate the more your
11 model is, the more bottoms up your model is.

12 I could be wrong, but if this is the case, and
13 we're not happy with the 8760, it's giving us screwy
14 results for some hours or months, well, in that case we
15 can continue to use the hourly load model and then, we
16 could calibrate that each year to the HELM 2.0 annual
17 peaks.

18 So, we've found that the original version of
19 HELM, even though it didn't perform very well for 8760,
20 it does give us a pretty reasonable peak forecast
21 comparing HELM output to actual history.

22 So, I'm confident, at least, that we'll have a
23 peak coming out of HELM 2.0 that, as I said, the
24 advantage of that is you can break it down into
25 different sectors and end uses. We'll at least have

1 that and, hopefully, we'll have more. We'll have a
2 full, reasonably, soundly performing 8760 hourly load
3 forecast coming from HELM.

4 We're now putting it through its paces and we
5 will see, and we're hoping to use HELM in some form.
6 We're planning to use the new HELM in some form for the
7 revised forecast, so we'll keep you posted.

8 COMMISSIONER MCALLISTER: Oh, okay. So, what
9 about the monthly peaks? So, you're corralled to the
10 confidence in the annual peaks or how are we thinking
11 about, you know, working through the monthly peak issue?

12 MR. KAVALEC: Yeah, so I think that would be the
13 same. It could be that HELM 2.0 performs well at the
14 monthly level, for monthly peaks, although not
15 necessarily for 8760, let's say.

16 COMMISSIONER MCALLISTER: Yeah.

17 MR. KAVALEC: Well, in that case, we could
18 calibrate the hourly load model, the more aggregate
19 model to monthly peaks from HELM.

20 COMMISSIONER MCALLISTER: Uh-hum.

21 MR. KAVALEC: So --

22 COMMISSIONER MCALLISTER: Okay. I'm thinking
23 of, you know, all the other uses for RA, and all those
24 other purposes.

25 MR. KAVALEC: Yeah, so, yeah, we'll just have to

1 see.

2 COMMISSIONER MCALLISTER: Yeah, okay.

3 MR. KAVALEC: We're going to run it through all
4 kinds of different tests and compare it to the hourly
5 load results we have now and, you know, take it from
6 there.

7 COMMISSIONER MCALLISTER: Yeah, okay. All
8 right, well, great. Thanks, Chris.

9 MR. KAVALEC: And jerk that I am, I didn't list
10 the names of all the people contributing to the
11 forecast, like Mark did.

12 COMMISSIONER MCALLISTER: Mark's making you look
13 bad.

14 MR. KAVALEC: But I will say, I want to thank
15 the 20 or so people that are directly involved in the
16 forecast, including the Transportation folks, the
17 Efficiency Unit, the sector modelers, and our data
18 people.

19 Okay, thank you.

20 MR. FUGATE: Okay, the last presentation is Cary
21 Garcia, again, to review planning area forecasts.

22 COMMISSIONER MCALLISTER: Just a reminder, I
23 don't think we have any blue cards. Do you have any up,
24 Nick? No. So, just if you're going to -- if you plan
25 on speaking or want to address in public comment, go

1 ahead and fill out a blue card.

2 MR. FUGATE: So, one of the ways we've done this
3 in the past is we have paused after each IOU planning
4 area and asked the utility, invited the utilities to
5 make any comments. So, if you're amenable to that,
6 we'll do the same thing.

7 COMMISSIONER MCALLISTER: Absolutely. And if
8 that's going to happen systematically, then they don't
9 need to fill out blue cards.

10 MR. GARCIA: All right. Chris was pointing out
11 that the Forecasting Unit is not as friendly as the rest
12 of our division, apparently. No thank you's.

13 COMMISSIONER MCALLISTER: Yeah, I think it's
14 just sort of a, you know, socially, well-adjusted, I
15 guess.

16 MR. GARCIA: You can say social awkward. They
17 get too many numbers. They don't talk to human beings.

18 (Laughter)

19 MR. GARCIA: All right. So, I'm going to start
20 with the folks that traveled the furthest, over 500
21 miles, which I think is San Diego. So, initially, I had
22 Edison here, so I'm going to skip to San Diego. I'm
23 trying to be aware of like traveling plans and things
24 like that. And then, I'll still go to PG&E after that,
25 because they traveled as well, and they're here, in

1 person.

2 So, real briefly, this is an overview of the San
3 Diego forecast, a rough overview of mainly the inputs.
4 So, this table here is the main economic drivers that I
5 showed for the statewide forecast, just broken out for
6 San Diego's planning territory, which is primarily the
7 County of San Diego, with portions of Orange County, the
8 way we've mapped it out. Essentially, their service
9 territory.

10 And so, you can see the population in
11 households, using the same projections that I mentioned
12 this morning, but there's a slight decline, once again,
13 in personal income. And the manufacturing sector, as I
14 pointed out as well, has also declined and a slight
15 decrease in commercial employment.

16 Though, obviously, we know we're kind of like at
17 maximum employment. So, what that means these days is a
18 little different.

19 But, anyway, so, ultimately and the forecast
20 shakes out to having residential and commercial sector
21 growth being, as Chris mentioned, those standard savings
22 do have an impact there in the forecast, particularly in
23 2029 when they're maximized.

24 And then, we also have around 300,000 electric
25 vehicles in there, totaling around 1,300 gigawatts of

1 load in 2030. Specifically, for light duty vehicles.

2 And I should also mention, I may have glossed
3 over it earlier, but Mark reminded me that we also
4 include those medium and heavy duty projections, that
5 the Transportation Unit prepared for us, into the
6 forecast and that will get lumped into the commercial
7 sector overall forecast.

8 And then, lastly, on this slide, I just point
9 out the PV capacity that Sudhakar pointed out, so you
10 know what we're working with when we're doing this
11 comparison. So, around 2,300 megawatts of PV capacity
12 for 2030. And all these comparisons are going to be for
13 our mid case. I won't go into the high and the low
14 cases very much, except for this very next graph, where
15 I describe them.

16 So, here we can see, ultimately, the forecasts
17 are not too different. You can see that adjustment
18 downwards, with that weather adjustment that was more
19 prominent for San Diego, as well as those standards
20 kicking in, in 2019, kind of making that hockey stick
21 down there at the bottom.

22 But, ultimately, the growth rate's about the
23 same, 1.4 percent versus 1.5, as you can see. And, once
24 again, the electric vehicles are -- do have an impact
25 and increase that consumption a little bit there at the

1 tail end relative to the starting point.

2 And in this consumption forecast, the industrial
3 sector definitely is bringing things down a tad, too.

4 So, all those pieces playing out there results
5 in this slightly lower growth in consumption.

6 So, moving from consumption to sales, this is
7 the -- what I was trying to characterize earlier today,
8 just in a graphical form. So, at the top there, you
9 have our mid consumption forecast that was on the
10 previous graph. And the difference between these two
11 lines, the green line being the sales, is essentially
12 the self-generation. You can see the numbers that I
13 pull out there, so all looking at 2030. So, around
14 4,800 gigawatt hours of self-generation impacts, those
15 energy impacts. Eight-five percent of that is going to
16 be PV and that capacity that I pointed out earlier.

17 And as Sudhakar pointed out this morning -- or,
18 this afternoon, actually, those commercial PV
19 installations are going fast than residential. And you
20 can see that effect at the tail end of the sales. You
21 can see that flattening out in comparison to consumption
22 forecast that is going pretty straight out to 2030.

23 And, ultimately, the additional PV is going to
24 bring down that sales number, but slight changes in
25 comparison to the previous forecast, in the mid case.

1 And so, we have had discussions with the
2 forecasters at San Diego Gas & Electric. So, comparable
3 EV and PEV impacts, looking at their submitted forecast,
4 essentially, just brought back in their efficiency
5 estimates to kind of create a baseline that we can
6 compare against our forecast. And so, ultimately, that
7 unmanaged forecast grows slightly faster than our CEC
8 baseline. But the unmanaged peak is growing very
9 similar to the CEC, but the 2030 estimate is higher due
10 to some differences in starting points, as well. But I
11 think we're on the same page.

12 We do want to talk a little bit about -- well,
13 going back to the EVs, it's definitely comparable in the
14 short term, but there's some long term differences we
15 discovered in that, and we want to dig into that,
16 particularly with our Transportation Unit a little bit
17 more.

18 And we did find some differences in our
19 commercial floor space projections, so that kind of
20 bumped up our commercial sales forecast in comparison to
21 what San Diego was presenting. So, we're going to
22 discuss that a little bit more, as well, and put San
23 Diego in touch with our commercial floor space modeler.

24 But at this point, I just want to invite San
25 Diego up to provide any comments, if they would like.

1 The moment of pause.

2 MR. SCHIERMEYER: Thanks, Cary. First of all,
3 I'd like to thank the CEC and the staff for all the hard
4 work in putting together this preliminary forecast. And
5 then, also, having calls with us to compare our
6 submitted forecast, and then providing additional
7 information. It was very helpful.

8 In reviewing --

9 COMMISSIONER MCALLISTER: Could you just state
10 our name and --

11 MR. SCHIERMEYER: Oh, I'm sorry.

12 MR. FUGATE: Just for the record, the court
13 reporter needs to know.

14 MR. SCHIERMEYER: Yeah, my name is Ken
15 Schiermeyer, and San Diego Gas and Electric. And in
16 reviewing the baseline forecasts, we agree the sales
17 look comparable in the beginning, and then they kind of
18 -- they differ in the end and we'd like to continue to,
19 you know, look into that with the CEC staff.

20 We'd also like to look at the baseline forecasts
21 with the new committed energy efficiency separated out.
22 That might help us with the comparison. And so, I've
23 asked Cary for that and he's graciously accepted to do
24 that.

25 We look forward to including the AAEE, when that

1 is available, you know, to compare the fully managed
2 forecast at that time.

3 And then, I think we'll reserve any other
4 comments after we've circulated information within our
5 company.

6 COMMISSIONER MCALLISTER: Great.

7 MR. GARCIA: Cool, thank you. Thank you, Ken.

8 So, I'm going to move on to Pacific Gas &
9 Electric. A similar summary. As you can see here
10 things are, in comparison to the other planning areas --
11 or, I guess, in comparison primarily to San Diego, the
12 IOU territories, PG&E's territory is split up into seven
13 -- or, sorry, six climate zones. And so, that's going
14 to be spread across all the way up to the North Coast,
15 down to portions of the Central Valley. The Sacramento
16 region down to Fresno/Bakersfield. Those are two
17 separate forecasting zones. We have a Central Coast
18 Zone, as well as a North Zone, a little further up in
19 the valley.

20 And so, we'll also provide these breakouts.
21 We're going to post the forecasting zone results, as
22 well, so you can see these comparisons. We weren't able
23 to do those in time for this workshop. They'll be able
24 to shed some light on what I'm discussing here.

25 So, similar story across the State. So, you can

1 see personal incomes going up a little bit here and
2 that's probably going to be driven by the Bay Area,
3 where you see those income growth being pretty high.
4 And that would be our forecasting zone, suitably titled
5 The Greater Bay Area, for PG&E. So, that's going to be
6 the City and County of San Francisco, and the
7 surrounding Bay Area counties.

8 In our forecast, it's currently around 1.6
9 million EVs by 2030. And you can see the break out of
10 that electricity impact there in the capacity of PEV by
11 2030, around 10,600 megawatts in our mid case.

12 So, moving on into the consumption, it's pretty
13 clear there's basically the same growth rates. There's
14 going to be a little dip there. As we've mentioned a
15 few times today, those standards are kicking in, in
16 2019, and then particularly for PG&E, we use those first
17 three years of rain data in the AG model, so that's
18 going to bring things down a little bit because you're
19 not having as much electricity usage for irrigation
20 pumping, as you would expect if you have more
21 precipitation.

22 As I mentioned, the Greater Bay Area is
23 definitely leading this planning area. So,
24 consumption's at one and a half percent per year, from
25 2019 to 2030. The same story with industrial mining,

1 that consumption is definitely down and declining across
2 the planning area, if you look at it on a forecasting
3 zone level.

4 But the Central Valley is still growing pretty
5 strong. And we all know it's going to have more houses,
6 large population growth there. And so, that's
7 continuing to increase commercial demand and the
8 residential demand in those particular forecasting
9 zones. And those would be this Sacramento region, as
10 well as the Fresno to Bakersfield regions.

11 Moving on to sales, you can see in this case,
12 with a little bit more PV that's going to bring down the
13 sales forecast, considering that the consumption
14 forecast is about the same. But, yet, the PV increased
15 a little bit here.

16 And, so, 96,600 gigawatt hours of sales. You
17 can see the self-generation numbers right there, 72
18 percent of which is going to be from PV. And another
19 interesting note about the Central Valley, so that
20 accounts for about -- once again, this is in 2030. So,
21 in our 2030 forecast, it accounts for about 50 percent
22 of PV generation in the PG&E planning area. But at the
23 same time, their per capita electricity sales are also
24 much higher than the rest of the planning areas. And
25 that's something I think we've sort of already known.

1 There's obviously some, many disadvantaged communities
2 in the Central Valley and we generally know there's a
3 lot of -- I mean, it's generally hotter during the year,
4 larger homes, potentially, in comparison to more urban
5 areas in the Bay Area, for example.

6 And here's where I touch on the comparisons
7 we've had. Similar to San Diego, we had discussions
8 with Pacific Gas & Electric. The quick comparison is,
9 really, PG&E has a higher EV forecast than we do, but a
10 slightly lower PV forecast. And so, there were some
11 differences in the modeling approach for EV that we want
12 to discuss a little bit more. And there's going to be a
13 difference in the capacity factors applied to the PV
14 forecast as far as the generation. So, we want to
15 discuss that as much as we can to make sure we're on the
16 same page there, and address any issues we may find
17 between our two forecasts.

18 And so, but ultimately accounting for these
19 differences, the sales forecast is comparable to the
20 CEC. Although, there's some slower near term growth,
21 but faster growth in the long term. A little faster
22 growth in residential and agricultural sectors in
23 comparison to our forecasts.

24 And then, there's slower growth in commercial
25 and industrial sectors. And similar to San Diego, I

1 haven't looked in detail. The issue with the commercial
2 floor space primarily came up with discussions with San
3 Diego, but we may take a second look at our commercial
4 floor space projections for PG&E, as well, just to
5 confirm that it's an isolated issue for San Diego,
6 specifically.

7 And then, ultimately, looking at the peak demand
8 forecast there at the bottom, we do have some
9 differences. PG&E's forecast is generally very flat and
10 then declining in the long term, where as our forecast
11 shows a little bit of growth, particularly a little bit
12 more in the long term, than PG&E's forecast.

13 But we've had those discussions and we're
14 working on finding ways to address that, address those
15 differences. At least to understand why those
16 differences exist and see if there's any changes we need
17 to make in our forecasting methodology there.

18 But at this time, if there's anybody from PG&E
19 who would like to comment.

20 MR. KOLNOWSKI: Good afternoon, Ben Kolnowski,
21 PG&E. I'd like to start off by saying thank you to the
22 CEC for the work and effort they put in to developing
23 the forecast, and especially the collaborative approach
24 that they've taken to share the results with us, and
25 discuss the results.

1 I have a couple comments. First is on the peak
2 demand forecast. I think Cary touched on some of the
3 differences there. We have a relatively flat forecast,
4 while the CEC's is slightly increasing. And I'd like to
5 dive deeper into what assumptions will come into play
6 once AAEE and storage are included in that forecast,
7 because I would imagine that would dampen that growth a
8 little bit and maybe bring us more in line.

9 And then, in terms of the sales forecast, I
10 think he correctly characterized that our EV forecast is
11 higher and the PEV forecast is lower for PG&E compared
12 to the CEC. And we'd like to dive into that further, to
13 explore those differences.

14 And the rest, we'll reserve some comments, as we
15 discussed internally, and dive deeper into the issues,
16 and submit some comments, written, by the timeline.
17 Thank you.

18 MR. GARCIA: All right, I'm going to back up a
19 little bit here and get back to Edison.

20 MR. FUGATE: I just want to make one point. So,
21 I think we've covered all the planning areas for which
22 we have utility representatives in the room. But if
23 there are folks on the phone, who are anticipating
24 making comments, please use the raise hand feature, on
25 the WebEx, so that we know to unmute you.

1 MR. HERNANDEZ: Excuse me, I'm here representing
2 Southern California.

3 MR. FUGATE: Oh, okay, I'm so sorry. Well,
4 then, we should have -- okay, so, I guess that will
5 apply for just L.A. and SMUD, unless I'm misspeaking
6 again. Okay. So, when we move into L.A. and SMUD, if
7 there's anyone on the phone who would like to make
8 comments, use the raise hand features, please.

9 COMMISSIONER MCALLISTER: Okay, great.

10 MR. FUGATE: Okay.

11 MR. GARCIA: All right, we missed you. We
12 apologize for that.

13 All right, so, we have the similar summary.
14 Once again, population, households, slight decrease here
15 in the personal income in comparison to the last
16 forecast, and manufacturing output, once again, is down
17 a little bit. And commercial employment stays about the
18 same.

19 So, a similar to story to PG&E, actually. So,
20 we see that population growth and the household growth
21 is going to be higher in those inland areas. And that's
22 primarily because it's just easier to build.

23 Like, for example, a portion of Edison's
24 forecasting zone is going to be Riverside County. And
25 so, it's just going to be easier to build there. Once

1 again, larger houses, faster population growth in those
2 particular areas.

3 1.1 million EVs and the 8,200 megawatts of PV
4 capacity in our mid case for 2030.

5 So, looking at consumption, not much change in
6 our two mid cases, that you can see there. Sitting, you
7 know, pretty right in the middle of our high and our low
8 cases here.

9 Residential and commercial sector is a little
10 bit lower, but still growing at similar rates as our
11 previous forecast. And then, that same story, once
12 again the industrial mining sector, as I mentioned, you
13 know, over the past decade or so that's been declining
14 and that's continuing to see that.

15 Inland and household population growth, as I
16 mentioned, is continuing. And so, Eastern and Big Creek
17 West forecasting zones, that's where the residential
18 sector seems to be growing the most.

19 Eastern, as I mentioned, is going to be that
20 Riverside County portion of Edison's planning area. Big
21 Creek West is going to be Ventura and portions of Santa
22 Barbara County.

23 And here's how everything shakes out as far as
24 moving from consumption to sales forecast. In this
25 case, a large portion of that self-generation is going

1 to be PV. You can see that at 75 percent there.

2 And then, kind of doing that comparison by the
3 forecasting zones, we see more PV impacts becoming
4 higher in the inland regions. Although, the actual
5 growth in PV capacity is still a little slower, on
6 average, in comparison to like L.A. Metro, for example,
7 which is going to be just right in the center of L.A.,
8 in Edison's planning area.

9 Sales forecast here that we're looking at, in
10 this comparison, so a fairly higher EV assumptions
11 according to Edison's forecast. But the PEV impacts
12 seem comparable there. Our capacity's about the same,
13 maybe a little -- some small differences. But we're, by
14 and large, pretty close together on that one.

15 Edison does show some declining sales forecasts
16 for their bundled customers, and a big portion of that
17 is load migration from Edison's bundled, to like CCAs,
18 for example L.A. County, being the largest CCA down
19 there at this point.

20 There are some differences in peak demand that
21 Chris pointed out today, in the previous presentation,
22 looking at those load shapes and issues around peak
23 shift. So, we'll have to dig into that a little bit
24 more, for sure, but we have discussed that with Edison,
25 through our DAWG, and through separate meetings with

1 their forecasting staff. And we seem to be on the same
2 page, we just need to work out these differences in our
3 forecast to get into the nuts and bolts of what are
4 assumptions are here.

5 And then, lastly here, you can see the peak
6 demand in their forecast is declining over the 10-year
7 period, whereas ours is slightly growing.

8 So, at this time I would invite you up to
9 comment for Edison.

10 COMMISSIONER MCALLISTER: That's for your
11 patience there. It was totally unintentional. So,
12 thanks for coming up in person.

13 MR. HERNANDEZ: Hello. Thank you, everyone. My
14 name's Sean Hernandez, representing Southern California
15 Edison. I'd like to thank the Commission for this great
16 work. It's a lot of work, a lot of numbers, and I know
17 everybody worked really hard on it and gave a lot of
18 considerations. Racked their brains, probably really
19 hard, thinking does this affect that, and does that also
20 affect this. So, thank you, everybody, I know it's not
21 easy.

22 So, I first wanted to comment that I did expect
23 to see a little bit more about natural gas demand in
24 today's presentations. I probably would have a few
25 follow-up questions for some of the staff members. And

1 also, Angela Tangetti and Anthony Davies regarding the
2 natural gas modeling.

3 My understanding is that there's an electric
4 sector optimization model that's used to calculate the
5 natural gas demand and I'm unclear at this time if that
6 work's been completed, yet. And I'd like to learn a
7 little bit more before we file our comments.

8 I'd also like to understand if that resulted in
9 a preliminary electricity price forecast, because the
10 natural gas demand forecast also leads to electricity
11 prices. So, that's very important, also, for the PV
12 forecast, for the TE forecast, as we all know.

13 Third, I'd like to mention some energy
14 efficiency food for thought. I'd like to encourage the
15 Commission to consider just a question, really, I don't
16 have any answers here, but does the new framework of the
17 Integrated Resources Planning proceeding call for
18 deciding EE portfolios in a new way?

19 In that proceeding, there is extensive
20 conversation about selectable versus non-selectable EE,
21 but so far, based on the fact the proceeding's using the
22 IEPR forecasts, it's remained only as a load modifier.

23 So, I would like to ask staff and the Commission
24 to consider what would be appropriate for increasing
25 that engagement between these two proceedings.

1 So, what would be selected if we did take an
2 approach like that and what role would the CEC like to
3 play in such an evolution, if it decided to?

4 Last issue, regarding Mr. Konala's presentation
5 on self-generation, I just wanted to flag the feature of
6 flat CHP forecast. In the previous IRP, that did create
7 a little bit of a controversy and a little bit of
8 modeling headache. It may not be reasonable to assume
9 that industrial CHP and electric sector CPH is remaining
10 flat, at a minimum, because the carbon allowance price
11 for Cap and Trade will be increasing, so there will be
12 an economic incentive for some of those units to be
13 taken offline.

14 And what the CPUC ended up doing is assigning
15 those CHP emissions to the electric sector, so that
16 basically crowded out what would have otherwise been
17 electric sector natural gas generation during ramping
18 and nighttime hours. And it's possible that that could
19 have reduced total system costs in IRP modeling.

20 So, we may need a forecast for CHP because it
21 does seem reasonable for it to be declining, instead of
22 flat. But happy to discuss these issues in an ongoing
23 manner with staff, and the Commission. Thank you for
24 your time.

25 COMMISSIONER MCALLISTER: Hey, thanks for being

1 here. Just a couple comments and maybe, Cary, you can
2 talk about the production cost modeling, the status of
3 the production cost modeling.

4 But to your point about sort of what happens in
5 an IRP procurement kind of scenario is right on. And,
6 you know, I don't think anybody really has the full
7 answer to that. But we are talking a lot with the PUC
8 about this. And, in particular, in the context of the
9 Energy Efficiency Action Plan that we're updating right
10 now, that will be sort of hitting the airwaves in the
11 next week or two. And we have a workshop, I think it's
12 on the 27th, about that.

13 So, that's a topic that we ought to air out
14 there. We ought to begin to think about how efficiency
15 can, you know, evolve to play alongside all these other
16 resources we're talking about, and alongside demand
17 flexibility, you know, more broadly, right.

18 So, I think all these topics are really in the
19 air and it's great if Edison can participate and sort of
20 bring that creativity, and all of us can sort of put our
21 thinking caps on. Because how -- you know, and the rate
22 regime going forward is really an integral part of this.
23 So, you know, everything's kind of related at this
24 point.

25 So, anyway, I really appreciate your comments

1 and expressing those thoughts. And then, you know, hope
2 to keep engaging on that really deeply. So, thanks.

3 MR. GARCIA: Yeah, and as far as the production
4 cost modeling, so these preliminary results will feed
5 into their work over there, the modeling, and then it
6 kind of iterates back.

7 If you remember the presentation I gave earlier
8 in the year, it's sort of an iterative process. So,
9 this preliminary will feed into that, and then those
10 numbers, from NAMGAS, for example, give us some gas
11 rates. That will feed back into our models and then
12 we'll get the whole process once again.

13 MR. HERNANDEZ: Thanks, Cary.

14 MR. GARCIA: Then, once we get this done, we'll
15 --

16 MR. HERNANDEZ: So, if I hear you correctly, we
17 have completed the electricity demand forecast, which is
18 going to go into that PCM I described, and then we're
19 going to get the natural gas demand forecast.

20 MR. GARCIA: Correct.

21 MR. HERNANDEZ: Terrific. Thank you, everybody.

22 MR. GARCIA: Okay, I'm jumping around here. All
23 right, we're going to go to SMUD, because that's the
24 next one I landed on.

25 So, as we talked about earlier and Sudhakar was,

1 in fact, right, the population growth in the Sacramento
2 Region is definitely higher than other parts of the
3 State. But the population households are locked in at
4 the same rate, roughly, as you can see in this table
5 here.

6 Personal income, once again down a little bit
7 there. Manufacturing output, as well. And then,
8 commercial employment stays about the same, although
9 there might be a slight adjustment downward there,
10 actually, because these are rounded up. So, there might
11 be some small changes.

12 Ultimately, there's slower growth in
13 residential. And it's a relatively small sector, as you
14 saw on the statewide level, but there was some
15 interesting information from the TCU sector. But,
16 ultimately, that slowed down in growth as well. And,
17 once again, that's going to be your transportation,
18 communications, and utility sector.

19 A hundred and twenty thousand EVs are assumed by
20 2030 and then, roughly, 660 megawatts of PV, as Sudhakar
21 pointed out earlier today.

22 Consumption is about the same, you know, only a
23 minor difference in the overall growth here. But those
24 new building standards do apply, as well, for SMUD. So,
25 that drops things down a little bit in 2019, in

1 comparison to the previous forecast.

2 And that little bit about TCU that I pointed
3 out, that was just me investigating probably a little
4 more than I needed to. But it was an interesting little
5 tidbit of information, just on the historical trends and
6 the telecommunications. So, what's happening in SMUD,
7 in particular, for the TCU unit, is there's the
8 transition from wired components to wireless. And so,
9 that employment and the work done in that sector has
10 dropped off, and the wireless technology is picking up.
11 So, that's just a little snippet of information.

12 And you can see this at a national level, where
13 things have sort of -- employment has been declining in
14 wired telecommunications technologies, and it's started
15 increasing in the wireless sector.

16 If you ever want to dig into NAICS Codes, it's
17 interesting stuff to get in there and to see this in
18 more detail, if you have a lot of free time on your
19 hands.

20 Moving from consumption to sales, you can see
21 here the impact of that PV generation. SMUD is a little
22 different where around 96 percent of the self-gen is
23 coming from PV, so that's a pretty large proportion.
24 And I think that's much higher than most other planning
25 areas in our State.

1 And I should also mention that SMUD is actually
2 not a planning area unto itself. It's a part of our
3 Northern California non-CAISO planning area that's
4 broken up into three forecasting zones. So, SMUD is one
5 of the three. Turlock, Modesto, and other portions of
6 the Balancing Authority of Northern California are going
7 to be the other two forecasting zones within that.

8 And then, back to here, though, so this PV
9 growth that we're seeing here just definitely results in
10 slower growth and sales in comparison to what we saw on
11 the consumption forecast on the slide previous.

12 So, I didn't talk about peak demand for the
13 IOUs, because we addressed that in the hourly model. We
14 haven't, yet, gotten to modeling peak demand for the
15 other planning areas that are at an hourly level, so we
16 use load factors that we have developed from our
17 previous HELM model to derive peak demand from the
18 consumption demand fed into it.

19 So, ultimately, as you saw on the previous,
20 you're going to see numbers very similar to consumption
21 because that's essentially what peak end use load is.
22 That's like going to be your demand, irrelevant of
23 generation source, just your raw demand for end use.

24 So, a modest decline here in peak end use load.
25 And that's going to be driven, as I said -- your peak

1 end use load is going to be driven by your weather-
2 sensitive sector, so residential and commercial. So, if
3 there's a decline in your commercial sector consumption,
4 you would expect a similar decline in overall peak end
5 use load at the end of the day.

6 This is a little, slightly more complicated
7 graph, but this is going from gross generation to net
8 peak, and then also to peak end use load. So, as I
9 mentioned, you can see peak end use load down there at
10 the bottom in the green line.

11 The difference between that and gross generation
12 is your losses, so you do that calculation of losses
13 there. And then, the difference between the gross
14 generation and your net peak demand is going to be that
15 self-generation impact.

16 So, ultimately, this is going to basically grow
17 out your sales rate, because it's essentially what it is
18 just on the peak side, when you think about it. And so,
19 1 percent in compared to 1.3 percent, slight decline
20 there. You're going to have more PV having an impact,
21 obviously, as well as the impacts that are happening on
22 the underlying sales forecast that's going to feed into
23 the peak demand forecast. So, as outlined here.

24 So, you see this -- I pointed out, at the bottom
25 there, you have this increasing self-generation impact

1 that results in that decline in your net peak, relative
2 to end use load. So, you see our end use load slowly --
3 your end use load, I guess, graph, and your net peak
4 graph slowly kind of reaching point as that self-
5 generation begins to increase at such a rate.

6 So, quick comparisons to SMUD's forecasts. So,
7 overall, it includes less PV and less EVs. But,
8 ultimately, we end up being on the same page there, at
9 the end of the day, in comparison to our forecasts.

10 We have some declining residential sales growth
11 in their forecast, but some large growth -- or,
12 actually, some growth in their large commercial customer
13 demand. SMUD breaks out their forecast into more
14 disaggregate customer classes, in comparison with us, so
15 that's what's going on there.

16 Ultimately, their sales forecast is pretty flat
17 over the 10-year period, and that's looking at -- that's
18 actually including sort of a managed forecast to include
19 energy efficiency over their demand forecasts, as some
20 of the other utilities that submit data to us, do.

21 But, ultimately, our forecast is showing a
22 higher residential and commercial demand. But when you
23 do that comparison to an unmanaged forecast, and you
24 basically bad -- we seem to add back the energy
25 efficiency savings to create an unmanaged for SMUD, and

1 we end up being pretty close to the same as far as
2 sales.

3 We do have similar growth expectations for peak
4 demand, when looking at like an unmanaged version of
5 SMUD's forecast. But their managed forecast shows a
6 decline over the long term period here.

7 And I don't believe we have anybody on the line
8 from SMUD, but if we do, I'll leave it there for
9 comment.

10 Okay, just a last note as far as the sales. So,
11 as I said, we're pretty close. And as I mentioned, SMUD
12 has less PV and less EVs. But on our end, we have more
13 PV and more EV, so it ends up being a wash as far as our
14 assumptions. We're not too far off, but we want to dig
15 into that and understand what's going on there. But
16 SMUD has pretty good on-the-ground information and
17 they're pretty involved in their EV programs.

18 COMMISSIONER MCALLISTER: Yeah, I would say
19 they're going to have really good information about --

20 MR. GARCIA: Yeah.

21 COMMISSIONER MCALLISTER: -- like they have a
22 very well-developed electrification program and, I mean,
23 I think they'll be able to help us anticipate pretty
24 well what's going to happen here.

25 I mean, one question I kind of have throughout

1 this is in the out years, you know, the interplay
2 between all these different wedges, and demand
3 modifiers, and everything, how much does some of the
4 uncertainty in each of those individual areas kind of
5 compound?

6 MR. GARCIA: I think it definitely does
7 compound, for sure.

8 COMMISSIONER MCALLISTER: Yeah, so like how much
9 -- what are the air bars around this stuff? Are they
10 getting wider over time and how can we deal with that,
11 or do we need to deal with that, I guess?

12 Anyway, but probably we can talk about that
13 offline. But, you know, I think there's -- there are
14 more sources of uncertainty --

15 MR. GARCIA: Yeah.

16 COMMISSIONER MCALLISTER: -- as we -- you know,
17 each new forecast and so, you know, how do we sort of
18 bound that?

19 MR. GARCIA: Well, yeah, so --

20 COMMISSIONER MCALLISTER: Yeah, I've talked
21 about this before with Chris a little bit but --

22 MR. GARCIA: Right. And so, well, just thinking
23 about what you had said about the -- and you can see
24 this comparison, as I mentioned before, like in our
25 short term we're all pretty close, we're not too far off

1 there. But as we start getting, you know, into that 5-
2 year period and beyond, that's when I start -- we start
3 seeing, just looking at our forecast in comparison to
4 the utilities' forecasts, we're definitely making some
5 different assumptions about what's happening in the long
6 term.

7 EVs, for example, in some of the utility
8 forecasts you see almost like Bass diffusion kind of
9 situation happening, where it may not be paying,
10 perhaps, not as much attention to policy impacts and
11 influence, as it may, but that's something that's hard
12 to put a confidence interval on, right. Like, what
13 happens with a certain, a new policy that may take place
14 that we weren't expecting? How do you model that out
15 ten years out from
16 now.

17 COMMISSIONER MCALLISTER: Yeah. I mean, that's going
18 to require some interaction, not only with the
19 utilities, and certainly first with utilities, but also
20 with the ISO and the PUC. I mean, particularly the ISO
21 like -- I mean, well, all the agencies have to plan out
22 a decade, right? I mean, it takes -- these
23 infrastructure projects and these investment plans, they
24 have to contemplate, you know, definitely more than a
25 few years out. So, we need to work pretty hard to

1 develop a comfort level with those sort of medium out
2 years, so that we can be on the same page with the
3 forecast.

4 MR. GARCIA: Do you have any comments?

5 COMMISSIONER MCALLISTER: I don't really see any
6 nodding heads in the audience, maybe one or two, but
7 anyway.

8 I mean, the last thing we want to do is, you
9 know, take the forecast to the agencies and say, okay,
10 well, do you see any problems with this and have them
11 say, yeah, you know, we're not confident in your fifth
12 year or your sixth year, you know.

13 MR. GARCIA: Right.

14 MR. FUGATE: I was just going to say that we
15 don't see any raised hands on the WebEx, but we do have
16 some call-in users. So, what we'll do at the end is
17 just open up the lines in case there are any comments
18 from anyone.

19 MR. KAVALEC: I just wanted to make one point
20 about uncertainty. And as you mentioned, and we've
21 talked about it in the past, this in the past. And,
22 really, what it comes down to, our users typically want
23 a point forecast. Maybe the way to think about
24 incorporating uncertainty in the future is to urge our
25 stakeholders, users of our forecasts, to start thinking

1 about using distributions of results instead of a point
2 forecast.

3 COMMISSIONER MCALLISTER: Yeah, thanks.

4 MR. GARCIA: Which portion of the distribution
5 should we pick, though?

6 All right, last, but not least, LAWDP. So, when
7 we talked about it earlier today, there's definitely
8 some -- an issue around the household projections that
9 we have for these climate zones. And so, L.A., as I
10 mentioned, is split into two climate zones. There's an
11 inland and a coastal. And so, we may want to actually
12 combine those. We're not too sure if there's much value
13 in having that before -- that's a carryover from how we
14 had done this decades earlier.

15 And so, that may be somethings that needs to be
16 addressed. It might help make it a little easier to
17 develop these household projections for LAWDP.

18 But nonetheless, here's the table breaking out
19 some of the projections. As with before, those
20 population households are going to be the same as last
21 year. Differences in personal income that you can see
22 here, as well as the manufacturing output and then, once
23 again, commercial employment is going to stay about the
24 same.

25 And then, I think it's the story across the

1 State that declining industrial and mining sector really
2 happening just about everywhere.

3 And then, you can see the EVs that we're
4 assuming for LADWP at the bottom there, around 370,000
5 light duty electric vehicles by 2030.

6 Looking at consumption, you can see that drop
7 there in comparison to the previous mid case, and this
8 is going to be due to the residential and commercial
9 consumption being slowed down due to those economic
10 drivers that I mentioned. So, personal income coming
11 down, low growth in households, as well as the standards
12 that we mentioned before.

13 Then, once again, industrial sector here is
14 declining much faster than 2018.

15 This is the sales forecast. You can see the
16 comparison at the top there. And as we noted before,
17 there's -- just looking at the numbers here, there's
18 much less self-generation in our forecast in comparison
19 to other parts of the State. So, we'll address that, as
20 I mentioned, through looking at the household numbers.
21 So, we can dial in those household additions and that
22 will increase the potential of roof space for the PV
23 adoption. So, we can fix that and look into that a
24 little further, and that might change these numbers for
25 the revised forecast, as they come up.

1 And, ultimately, this shakes out to having PV
2 capacity growing a little slower than the statewide
3 average.

4 Peak end use load, here it's much lower. Those
5 weather-sensitive sectors are really going to drive the
6 peak end use load, as I mentioned, for SMUD. And so, if
7 you have a lower residential and commercial sector
8 consumption, that's ultimately going to lead to lower
9 peak end use load growth.

10 And you can see the differences there, 1.2
11 percent versus .6 percent that we have now. So, it's a
12 little bit slower growth. But, yeah -- yeah, much lower
13 low case as you can see, pretty obviously. And the high
14 case is a pretty tight balance from those two numbers.

15 Moving from peak end use load to the net peak,
16 you can see the self-generation impact. Only about 280
17 megawatts of peak -- of PV at that peak there. So, once
18 again, that slower peak end use load growth is going to
19 result in a similar slow down in the net peak forecast.
20 In this case a little bit more significant, 0.4 percent
21 versus 1 percent here.

22 So, LADWP's forecast for sure includes more EVs
23 and PEVs -- PV, and as well as EVs. As I said, there is
24 lower residential and commercial sales forecasts.
25 That's going to lead to an overall lower forecast in

1 comparison to the CEC. Aside from those sales
2 differences, the peak forecast is pretty comparable.
3 We're definitely, also going to see that the peak
4 forecast that we're using actually has a lower starting
5 point in comparison to what they have. So, we want to
6 take a look at that a little further. And we're reached
7 out to LADWP staff to set up a call at some point,
8 shortly after this workshop.

9 I mentioned before looking at LAWDP housing. We
10 want to dig into that a little bit further and see
11 what's going on in those projections.

12 There is a significant reduction in there, as I
13 said here, in their residential and commercial sales,
14 but they also have a higher peak demand forecast, which
15 has me scratching my head a little bit. I don't quite
16 understand how the overall sales could be declining, but
17 yet, you have a much higher peak demand forecast than we
18 have, when we have these differences in both our
19 forecast. So, this could be driven by differences in PV
20 and EV. And I noticed it more in their commercial
21 sector. There's quite a bit of a decline downward that
22 seems a little peculiar, and then it starts dipping up.
23 So, it's sort of like a little Nike swoosh, for example,
24 happening in their forecast for commercial sector,
25 specifically. So, we'd like to dig into that a little

1 bit more and find out what's going on in there.

2 But I don't believe anybody on LADWP's on the
3 line. But I think at this point, we'll just opening it
4 up, if there's any additional public comments before we
5 go.

6 MR. FUGATE: So, actually, we do see at least
7 one LADWP representative. Is his line unmuted?

8 MS. ZHANG: This is Bingbing Zhang from LADWP.
9 Can you hear me?

10 MR. FUGATE: Oh, yes, we can hear you.

11 MS. ZHANG: Oh, okay. Yeah, thank you for
12 everybody putting into all the effort put into this
13 detailed forecast. So, I heard all your questions and
14 so, we'll be happy -- I will be happy to assist you guys
15 with all the questions and so we can learn more from the
16 forecast. And, also, I will be interested in, you know,
17 getting more details on the hourly forecast and also the
18 peak hour shifting, if you guys have any additional, you
19 know, input, so we can improve our forecast as well.

20 MR. FUGATE: Okay. Thank you, Bingbing.
21 Currently we do not hourly forecast the LAWDP, but
22 that's something that we can talk about the future for
23 sure, and we'll definitely reach out to you guys soon.
24 I think I reached out to the colleague who submitted
25 your IEPR demand form. So, I'll make sure to include

1 you in that communication, as well, as we can follow up.

2 MS. ZHANG: Yes. They are the coordinated our
3 LAWDP communicating with CEC. So, yes, I will make sure
4 that they will, you know, include us in this discussion.

5 And another quick answer to one of the questions
6 you had, how come our peak demand goes higher, while our
7 consumption forecast goes lower? Was that one of your
8 questions?

9 MR. GARCIA: Yes.

10 MS. ZHANG: So, the way basically was not using
11 the same load factor to forecast for the future. We
12 forecast our load factor, as well. So, in the past
13 several years, the load factor has been dropping down.
14 That's probably one of the reasons causing the increase
15 of peak demand, however the consumption has been lower.

16 MR. GARCIA: Okay, thank you. Yeah, we'll
17 definitely follow up with you, Bingbing and have a more
18 -- a deeper discussion on that. That would be great.

19 MS. ZHANG: Okay. All right, yeah, I'm looking
20 forward. Thank you.

21 COMMISSIONER MCALLISTER: Did we open all the
22 lines? Okay, so I think we should be good.

23 MR. FUGATE: Okay.

24 COMMISSIONER MCALLISTER: Any wrapping up
25 comments, deadlines, housekeeping stuff?

1 MR. FUGATE: Yes, so I believe the comments for
2 this workshop are due on August 29th. That's in two
3 weeks.

4 COMMISSIONER MCALLISTER: Great.

5 MR. FUGATE: So, I want to thank everyone for
6 coming.

7 COMMISSIONER MCALLISTER: Yeah, I guess I want
8 to thank Cary for the presentation and all of you for
9 sticking it out to the last. It's a little sparse,
10 you've got the diehards here in the room.

11 But, you know, this is not the most accessible
12 conversation, but it is absolutely one of the most
13 important conversations we have at the Energy
14 Commission. And it ends up with a really robust
15 platform for having discussions about how we do our
16 energy planning going forward.

17 And as we transition to, in many ways, actually,
18 our energy sector an as we sort of morph between gas and
19 electricity, and we try to figure out about demand
20 flexibility, and disaggregation, and locational,
21 temporal, all of the different trends that we're seeing
22 across the State, it all kind of comes home to roost
23 right here. And so, this conversation is really
24 critical and we have to produce a good product so we can
25 have, basically, a consensus across the State that it's

1 going to be used going forward. And this is the common
2 language we're going to use.

3 And so, anyway, I want to just thank everyone
4 for your participation. And, certainly, thank staff in
5 the Demand Analysis Office, and just everybody in the
6 Assessments Division, and the other divisions who
7 contribute to getting this train rolling down the track.
8 And we have a few stops to make along the way, but we'll
9 get to our destination here before January, by January
10 of next year. So, thanks again.

11 Anything else? All right, thanks, everybody for
12 coming. We're adjourned.

13 (Off

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(Thereupon, the Workshop was adjourned at
4:03 p.m.)

REPORTER'S CERTIFICATE

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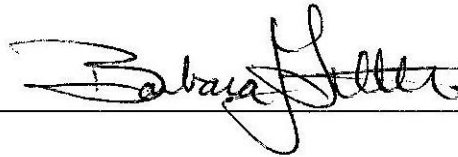
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