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IEPR JOINT AGENCY WORKSHOP OF THE CALIFORNIA ENERGY
COMMISSION, THE CALIFORNIA PUBLIC UTILITIES COMMISSION, AND
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR

In the Matter of:)
) Docket No. 17-IEPR-07
2017 IEPR Joint Agency Workshop on)
the Increasing Need for Flexibility))
in the Electricity System)
_____)

CALIFORNIA ENERGY COMMISSION
ROSENFELD HEARING ROOM - FIRST FLOOR
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

FRIDAY, MAY 12, 2017

9:30 A.M.

Reported by:
Peter Petty

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P R O C E E D I N G S

9:33 A.M.

SACRAMENTO, CALIFORNIA, FRIDAY, MAY 12, 2017

MS. RAITT: Good morning. Welcome. Welcome to today's IEPR Workshop, a joint agency workshop on increasing need for flexibility in the electricity. I'm Heather Raitt, the Program Manager for the IEPR. I'll go over our usual housekeeping items.

If there's an emergency, please follow staff through the -- exit the building to Roosevelt Park, which is across the street from us. Please be aware that we are being broadcast through WebEx, which is being recorded. We will have an audio recording posted in about a week, and a transcript, written transcript, in about a month.

Our agenda is very full, so I please ask our speakers to stay within your allotted times. We do have a public comment period of the end of the day, and will be limiting those to 3 minutes for each speaker. If you'd like to make a public comment, please fill out a blue card. And you can give it either to our Public Adviser, Renee, or to myself.

For our WebEx participants, please raise your hand to tell our WebEx coordinator that you'd like to make a comment, and we can open your line at the end of the day

1 during the public comment period.

2 All the materials for this workshop are available
3 at the entrance to this hearing room, and also posted on our
4 website. Written comments are welcome and due on May 25th.

5 And I'll turn it over to the Chair. Thank you.

6 CHAIR WEISENMILLER: Thank you. I'd like to thank
7 everyone today for their participation.

8 I think just sort of looking at the reality,
9 obviously, California is on a pathway of transforming its
10 grid, along with actually transforming it's, as the Governor
11 said in the State of the State, its communities, its
12 transportation system, its buildings, and certainly the grid
13 is part of that. And part of that transformation is more
14 and more renewables on the grid. And as you do that, I
15 mean, there's some basic physics. Renewables tend to be
16 variable in nature. And so we're looking at a potential
17 variety of solutions.

18 We realize that these issues are by no means
19 unique to California. I think I've been to Germany on these
20 very issues now, I'm trying to remember whether it's three
21 of four times. And certainly the Germans are experiencing
22 similar issues. As you go to China, where I've also been a
23 couple of times on the grid. Certainly, they're viewing
24 similar issues. As you go to Texas, ERCOT, Texas talks now
25 about the dead armadillo, as opposed to the duck curve.

1 Obviously, things are obviously different in Texas than in
2 California. And I'd say, actually, I'm always surprised the
3 Chinese never quite pick up on the duck curve there. But
4 anyway, it's a basic phenomenon.

5 So today, we're looking much more at solutions.
6 Obviously, part of those solutions is if we can get variable
7 load to match the variable supply, but there's sort of a
8 range of options. Some of them are more significant than
9 others. Although, frankly, I think we're going to need a
10 portfolio of solutions. And today, we're going to try to
11 explore those solutions.

12 Obviously, the other thing we're seeing is we've
13 gone from, you know, what's been a record drought to what's
14 not quite a record hydro condition this year, but pretty
15 close. And certainly the swing in hydro really exacerbates
16 these issues, and just as the drought really muted the
17 issues.

18 So at this point, we're looking for solutions.
19 And, unfortunately, we're not going to find any in the next
20 month. But, you know, certainly as we go forward with
21 climate change we expect a much more volatile hydro system.
22 And so, you know, on one hand, hydro has been a very key
23 part of our resource mix, low carbon. Some of it is
24 flexible, some of it is not. But also, it will swing from
25 year to year and that's sort of phenomena. Certainly, when

1 you talk to people in Germany or China or Texas, they don't
2 have anywhere close to the same level of hydro, so the same
3 level of variability. And so one of the things we need to
4 deal with over the long term is, again, the hydro variation.

5 So anyway, thanks for being here.

6 Commissioner Randolph, I want to thank you for
7 coming today.

8 COMMISSIONER RANDOLPH: Thank you. I make it just
9 in time.

10 As Chairman Weisenmiller mentioned, I mean, we do
11 have a changing grid. We do have significant GHG reduction
12 goals we're trying to meet. And we're trying to create a
13 system that will accommodate those goals but ensure the
14 reliability that California residents have come to
15 appropriately expect. And that's also, you know, needed for
16 our -- our economy that is so highly dependent on energy to
17 all of our tech companies and server farms and connectivity
18 that we expect in this state.

19 And as Bob mentioned, I mean, it is -- there are a
20 lot of solutions out there. And the solutions -- the suite
21 of solutions keeps getting broader as some of the research
22 that the ISO has been doing with solar providing more grid
23 support at night. Some of that research at some point may
24 grow into real actual practical solutions.

25 And so the key for us is figuring out how we can

1 take the solutions we already have, take the solutions that
2 are being developed, and make sure we are managing them in
3 the right way and putting them together in the right way.
4 And the integrated resources planning process that we are
5 undergoing at the CPUC is going to be a big part of that
6 discussion. And our Energy Division Director, Ed Randolph,
7 is going to be here today to present sort of where we are
8 with that process and what we can expect from our CPUC staff
9 as they release their proposal over the next couple of weeks
10 to lay out the IRP process, so looking forward to hearing
11 that presentation.

12 And I really want to thank all of the panelists
13 for coming today and being willing to talk about these
14 important issues. Thanks.

15 MR. DOUGHTY: Well, Chair Weisenmiller, good to be
16 here with you again. The ISO is really glad to be
17 participating today. And looking over the agenda and the
18 materials, I think we're going to have a really healthy and
19 informed conversation today. We're going to hear about new
20 operational paradigms that are defining a new electric grid.
21 We're going to discuss terms that we've all heard before,
22 like oversupply and ramping and curtailment. We'll learn of
23 trends that are reflecting the growth in those new
24 circumstances.

25 As this discussion unfolds, both in this room and

1 elsewhere, some might be tempted to say, what an awful
2 situation, turning off renewables, managing big ramps. Boy,
3 this is a terrible set of circumstances. We see it
4 differently. We see this as a moment to acknowledge the
5 incredible and unprecedented journey upon which California
6 has embarked as we pursue this low-carbon grid.

7 We see this also as a moment to pivot, and the
8 Chair mentioned this. Instead of grouching and grumbling
9 about new operational circumstances, we suggest that we use
10 our energies, re-channel them to solutions that can help
11 resolve these new operational considerations, but also
12 benefit our economy and our society.

13 When you think about it, California has invested
14 billions of dollars over the last decade in renewable
15 energy. And now a dividend on our investment is being paid,
16 and it's in the form of clean surplus energy. We're really
17 in the middle of the most resounding first-world problem you
18 could have, abundant, clean, low-cost excess energy,
19 available in the middle of the day to power our industry,
20 our homes, our businesses, our automobiles. And our charge
21 is to unlock that dividend, use it, benefit from it.

22 Ever since the first duck curve was published,
23 many have considered the growth of renewables to be a
24 burden. Some have said, well, this is difficult. The ISO
25 must really be resistant to these policies. Nothing could

1 be farther from the truth. We fully support the state's
2 goals. We've allocated our corporate and our individual
3 energies to helping to achieve them.

4 It's not to say it's easy. Everybody in this room
5 knows that. It's going to require out-of-the-box thinking
6 to unlock the value of this surplus energy. And it's going
7 to take thoughtful planning to navigate uncharted waters
8 around fossil retirements, ramp management, curtailments,
9 variability, intermittency. But in the end, if we are to
10 have a low-carbon grid, those waters really do need to be
11 navigated. And we're very eager to be working with you,
12 Chair, with the PUC, and all of you to navigate these
13 unprecedented circumstances.

14 So with that, Mr. Chairman, thank you so much for
15 including us. Looking forward to today's discussion.

16 CHAIR WEISENMILLER: Great. Thank you. Let's go
17 to the first panel.

18 MS. RAITT: Yeah. The first panel on Operational
19 Issues and Solutions, and Mark Rothleder from the ISO.

20 MR. ROTHLEDER: All right. Chair, Commission,
21 thank you for the opportunity for me making this
22 presentation. It's probably now been five years since I've
23 been making these types of presentations. And I can
24 remember back when I had to put graphs together of what
25 things we expected to occur. Fortunately, now we can

1 describe what is occurring and what's going to happen
2 further in the future.

3 My presentation today is going to just give you a
4 little bit of highlights, kind of set the stage for the rest
5 of today's discussions. I'll go through some information
6 that illustrates what is happening. I will go through a
7 couple of areas where there's opportunities based on what
8 we're seeing and what we expect in the future, and then kind
9 of highlight, which we'll probably discuss more in detail,
10 some of the solutions for what we are observing and what we
11 expect to observe in the future.

12 As Tom indicated, there's a lot of things that are
13 acting on the energy infrastructure, on the energy sector in
14 California. A variety of new goals, 50 percent, 100
15 percent, changes in gas infrastructure, political changes,
16 changes in fossil plants, consumers actually becoming
17 prosumers, grid modernization, all sorts of things are
18 acting on the energy infrastructure. And they are all
19 interrelated and they all act a little differently, and we
20 have to factor all of these in as we look towards the
21 future.

22 What I'm going to talk a little about is where we
23 are today and what we've seen. In terms of the growth of
24 renewables, a couple of things we should get oriented on.
25 In terms of wind, we've got about 4,700 megawatts peak wind

1 production in 2016. Every day or every week it seems like
2 we get a new solar peak. We are right just under 10,000
3 megawatts solar peak production. Two years ago that
4 probably would have been about 7,000, so we're continuing to
5 see the increases of solar.

6 Simultaneous wind and solar, just interestingly on
7 April 23rd, and I'm going to talk about April 23rd in a
8 couple of places in my material, we had about 13,000
9 megawatts of simultaneous wind and solar production. This
10 is all grid side.

11 On the rooftop or the behind-the-meter side, we
12 are now approaching or just over 5,000 megawatts of the
13 estimated capacity.

14 As we move forward from this level, we do expect
15 that as we approach 50 percent, whether it be in 2030 or
16 2026 or whatever it may be, there's going to have to be an
17 additional approximately 10,000 to 15,000 megawatts of new
18 renewable resources to achieve that target. We don't quite
19 know what those resources are yet. We're eagerly waiting to
20 see what the Integrated Resource Plan foretells in terms of
21 what the future makeup of those resources are. But I think
22 there's at least a high expectation that there will be -- a
23 fairly large expectation that there will be a solar -- a
24 fairly high solar mix in that portfolio.

25 On the behind-the-meter, as I indicated, we're at

1 5,000 megawatts right now. We're continuing to see the
2 growth into 2020. And expectations are that we'll be right
3 around 12,000 megawatts of behind-the-meter solar on the
4 system. And just comparing, I mean, that's more than the
5 grid-side solar than we have today.

6 This all comes to kind of what we're been using as
7 illustration of the -- to illustrate how this is changing
8 the system, and the duck curve is that illustration. As we
9 get more and more renewables, especially that midday solar
10 production, we're seeing the belly of the duck continuing to
11 decrease and deepen in its level. We expected by 2020, we
12 would be about 12,000 megawatts of net load. Net load is
13 measured as wind -- I'm sorry, load minus wind minus solar.
14 We've already achieved this year a 9,187 megawatts net load.

15 And you can ask, well, why? What happened? Where
16 did we go wrong in the estimation? And I think one of the
17 areas that we estimated incorrectly at the time when we put
18 the duck out is we didn't fully account for the behind-the-
19 meter growth of solar. And I think that accounts for where
20 we are today versus where we expected to be at this point.

21 We're now forecasting net load conditions. And,
22 in fact, this weekend we are forecasting that we are going
23 to be somewhere below 10,000, possibly approaching 9,000
24 megawatts of net load, a low-load day, moderate
25 temperatures, high production with the clear skies, and

1 potentially some fairly good wind production.

2 The other thing the duck has been telling us and
3 we expected is that we're going to see increasing ramp,
4 steeper, longer ramps in the evening, and we've seen that.
5 We've seen -- we haven't quite achieved the 13,000 megawatt
6 three-hour ramp in the evening, but we're very close to
7 that. So in those evening ramps, we need resources that are
8 basically moving and ramping to balance the system during
9 that time.

10 And the two put together, and if you think about
11 the belly of the duck, we're trying to get as many resources
12 off the system as much as we can to make room for the
13 renewables. At the same time, we have to keep a certain
14 amount of resources on that are rampable as we move into the
15 evening, when we take that 13,000 megawatt ramp. And that
16 transition from the low-load oversupply condition to the
17 head of the duck is kind of the operational challenge that
18 we are encountering today.

19 We should not -- we should not forget about why
20 we're doing this. We're moving into the renewables, we're
21 doing this because we want to reduce greenhouse gases. And
22 this graph illustrates that we are, indeed, we're seeing
23 those reductions.

24 We've got four years of comparison here, month by
25 month. And you can see, year over year we've seen a nice

1 steady decrease of GHG production to serve ISO load. So we
2 are successful in having the renewables integrate and
3 actually reduce, ultimately, the GHG gases.

4 So I'm going to now talk a little bit about
5 opportunities. But before I do so, I want to just put one
6 more set of numbers into the discussion today.

7 We talk about 33 percent. We talk about 50
8 percent. We talk about 100 percent. Where are we today?
9 And this is going back to an April 23rd day, again,
10 relatively mild load. But on this day in the middle of the
11 day we had 58 percent of the system load at the time being
12 served by wind and solar resources. We had 65 percent of
13 load being served by renewable resources. And one more
14 metric that we measure is 83 percent at that time was being
15 served by carbon-free resources. It's pretty impressive
16 what we've been doing. And we never really look at these
17 detailed numbers, but it indicates that we can do this. We
18 need to do it more often and we need to do it in a way that,
19 again, maintains reliability. And I'm going to use this
20 graph later on in the presentation to discuss what was
21 actually ramping in the evening and actually carrying the
22 flexibility.

23 So opportunity one, we often talk about oversupply
24 and curtailment, and we often talk about it as being a
25 challenge. And in light of what we're talking about today,

1 it really is an opportunity. It's an opportunity to do
2 something with this energy, rather than curtailing it. We
3 can use it to continue to reduce greenhouse gases by
4 displacing other emitting resources in other parts of the
5 system. But before we do that we have to kind of measure,
6 where are we at right now?

7 And what we've seen and what we're seeing this
8 year is an increase in the amount of oversupply and
9 curtailment. In the first quarter of this year relative to
10 the first quarter of last year, we've seen more than a
11 doubling of the amount of curtailment on renewable
12 resources. Now that's all because, one, we're successful in
13 having more renewable resources. Two, it's occurring
14 because we also have a good hydro year, as you indicated
15 earlier. And the combination of those in the middle of the
16 day are increasing that period of time where we're seeing
17 oversupply conditions. And we are, at times, having too
18 much energy, and at that point we have to curtail some of
19 that energy.

20 Now some will ask, well, how much of this in the
21 big scheme of things is this? In the big scheme of things,
22 right now it's running -- about two percent of the total
23 wind and solar energy is potentially being curtailed.
24 However, on specific days, we do see, at times, 20, 30, and
25 on specific days more than 30 percent being curtailed on a

1 specific day. So if we target those days, those periods
2 when we're seeing this higher level of oversupply and
3 over -- or curtailment and we target those, what can we do
4 in those periods to reduce that and do something with this
5 energy? That's the opportunity that we're looking at.

6 The next opportunity, and it's related to the
7 oversupply, is that when we get into these oversupply
8 conditions, you effectively get to the point where your
9 marginal price of energy is not being set by a fuel-based
10 resource. It's being set by the renewables themselves. And
11 the renewables themselves often times will have a very low
12 and potentially negative price. And that negative price is
13 their indication of their lost opportunity, lost opportunity
14 to get the Renewable Energy Credit, lost opportunity on tax
15 credits. So their expressing their cost of reducing as
16 being a negative price at that point. And we're seeing an
17 increasing frequency of these negative prices, and they're
18 not just random, they're in the middle of the day. We know
19 we can kind of start to predict even forward, day ahead and
20 in real-time, when they're going to occur.

21 And that's a good thing. Because if we can
22 forecast these, then we can do something with them. And
23 what we'd want to do something with those negative energy
24 prices is incentivize innovation in terms of demand
25 response, storage, and other innovative technologies that

1 can use these negative prices to actually reshape the load
2 curve.

3 The next opportunity is more of kind of an
4 operational one. And I know this is a complicated graph,
5 and I'll just try to briefly describe it. The backdrop is
6 the flat green line, if you're going to analogize it to
7 golf, that's your par line. Okay. That's where we want to
8 be. We want to be above the line. And what it's measuring
9 is our ability to hold frequency, that's our primary
10 responsibility as an operator, maintain 60 hertz, and make
11 sure that we are not sending more energy out of our system
12 or receiving more energy into the system than what we had
13 scheduled.

14 So if you consider that the par line, the bars,
15 the blue bars above the par line are hours in which we
16 exceeded par. Okay. We exceeded the performance standard.
17 It's a North American Electric Reliability Standard, Control
18 Performance Standard number 1. The red bars indicate when
19 we were below par. And effectively, we were not able to
20 hold the expectation of the frequency. We were not holding
21 the interchange with our neighbors.

22 Now this measurement is not just a spot
23 measurement where you're good or bad on any particular hour.
24 This measurement is measured over an entire year period.
25 And on average over the year, we need to be above the green

1 line, above 100 percent or par. But we're seeing increasing
2 periods where in the middle of the day we are finding
3 ourselves challenged to get to par or operating below par.

4 Now, if you come back and see the green wiggly
5 line and the yellow line, the yellow line is the solar
6 production on this particular day. The green line is the
7 wind production. And what you see here is that you're
8 seeing a level of volatility. And we're experiencing a
9 level of volatility in that production that we haven't
10 experienced before. And we are seeing, basically, at times
11 over a 30-minute to 60-minute period, we're seeing changes
12 of 1,500 megawatts to 2,000 megawatts over short periods of
13 time.

14 This is not unexpected. We knew that when we were
15 moving into the 33 percent range, we knew that we'd have
16 this higher level of variability. And we anticipated that
17 we would need to potentially carry additional reserves. Now
18 for this type of events, it's not our traditional operating
19 reserves. What we carry is more what we call flexibility
20 reserves, and we created new products to support this.

21 Nonetheless, these events are increasing. The
22 magnitude of this variability is increasing. And we have an
23 opportunity to use both these resources and use other
24 innovative resources to better manage and anticipate this
25 variability. This is an opportunity for us to operate

1 better and use the full set of resources in a way to help
2 manage operability.

3 The next opportunity is in the forecasting space.
4 With the level of renewables that we have on the system, the
5 magnitude of renewables, it's becoming ever more important
6 that we have good forecasting techniques. Because when we
7 miss the forecast, it has more significant impacts.

8 And this is just an example where on a day, and
9 this is a summer day, where we had anticipated roughly about
10 4,000 megawatts of solar production, and a lot of that is
11 coming from the fields over in the desert area. On this
12 particular day, we had monsoonal conditions. Monsoonal
13 conditions are moisture or cloud cover that comes up from
14 the southwest and moves over, unfortunately, right over the
15 fields that are producing a lot of that solar energy. And a
16 day ahead we anticipated 4,000. In actuality, we had about
17 2,000 megawatts less production as a result of those
18 monsoonal conditions.

19 And you can say, well, okay, well, you can
20 anticipate that even closer in. But believe it or not, even
21 the techniques that are available today, the best techniques
22 are not able to anticipate the cloud formations that
23 produce -- that are accumulating over the fields. They're
24 good at tracking west to east movement of clouds. But
25 they're very difficult -- the techniques are very difficult

1 at anticipating the increases or growth of cloud cover over
2 the fields. And so even in real-time, 30 minutes, and even
3 10 minutes ahead, we see significant differences between
4 actual and forecasted conditions.

5 So there's efforts underway. We're working with a
6 variety of folks and leveraging the CEC's funding to
7 actually develop some new techniques in the forecasting
8 area.

9 This is one form of forecasting. As I mentioned
10 earlier, we're also using this forecasting to actually
11 anticipate and forecast things like oversupply conditions.
12 We're now putting out reports or anticipation of over
13 forecasting oversupply conditions so that day ahead, even,
14 actions can be taken.

15 So the point is, is the forecasting will continue
16 to need to develop as we move to higher levels of
17 renewables.

18 The next opportunity is really a resiliency one.
19 As we have increasing numbers of renewables on the system,
20 we've introduced a new type of technology, inverter-based
21 technology, to the grid. And we're still learning and we've
22 still experiencing things that we didn't anticipate. They do
23 not ride through faults the way a rotating mass rides
24 through a fault. And we have seen at times, and other areas
25 have experienced at times, where during faults some of these

1 resources actually trip off and actually exacerbate the loss
2 of supply during the fault, rather than helping.

3 So there's efforts underway. We're working with
4 reliability organizations. We're working with the inverter
5 manufacturers and the developers to identify where we need
6 to -- where we need to retune and make sure that these
7 resources are really staying on the system during these
8 faults and helping the system through these events.

9 If we can keep them on the system, then we're
10 going to talk about some things that we can do with these
11 resources. Clyde Loutan will be talking right after me
12 about how we can actually use these resources to actually
13 ramp, even for frequency response or regulation and voltage,
14 and we've actually demonstrated how we can do that. But in
15 order to do that, they have to be fault resilient and they
16 have to remain on the system.

17 So those are the opportunities.

18 And now I'm going to move into kind of some of the
19 solutions. And there really is a suite of solutions.
20 There's not -- as we move from 30 percent to 50 percent and
21 beyond, there's no silver bullet. There's no silver --
22 there's no single solution that's going to help manage all
23 of it. We have to really look for a suite of solutions.
24 And these are just probably some of them. There's probably
25 other ones that are not on this list that we're going to

1 talk about today, but I think this is a good list to start
2 from.

3 Storage, whether it be battery or bulk storage,
4 being able to use those storage resources to shift load
5 around, store it, get frequency response from it, using
6 those resources in those ways to meet grid reliability.

7 Demand response, and when I talk about demand
8 response I'm not just talking about response to an event or
9 reducing load. We need smart demand responses that's
10 actually responsive to actual system conditions when we're
11 in oversupply, as well, so more of the prosumer, where
12 demand is actively participating and balancing the system.

13 And related to that is kind of time-of-use rates,
14 because time-of-use rates provide the retail customer an
15 opportunity to be responsive to system conditions through
16 when they're using it, as long as those time-of-use rates
17 are aligned with actual system conditions. If they're
18 misaligned, we actually can send counter signals that are
19 actually exacerbating and not helping the system conditions.

20 Minimum generation. This gets at how do we get
21 the fleet and transition the fleet to be more -- less of a
22 burden of being -- bringing energy onto to the system that's
23 not needed when you need it? And that goes to having
24 resources getting lower minimum loads, fasting starting
25 resources, retooling those resources, and maybe even getting

1 off of resources that have minimum loads altogether. Maybe,
2 in combination with batteries, we don't even have to have a
3 minimum load on a resource because we can quickly start it
4 when we need it to ramp.

5 Move into other areas. The Western Energy
6 Imbalance Market is one example where have now started to
7 leverage other parts of the interconnection to manage the
8 changing conditions in the system, whether it be sharing
9 oversupply -- good morning -- oversupply, sharing
10 flexibility, getting the most economic dispatch out of the
11 system.

12 And then there's broader regional coordination
13 efforts that are explorations underway. We did several
14 studies last year in SB 350. But there's also other
15 discussions going on about how can you leverage the external
16 part of the system and coordinate operation in the day-
17 ahead, forward, real-time to enhance both reliability and
18 provide cost effective, efficient dispatch across the
19 system.

20 Electric vehicles. We've got efforts underway to
21 increase the number of electric vehicles. That may
22 become -- if you can charge them at the right time, they
23 actually can use some of that oversupply and actually can
24 generate into the system if you have smart charging
25 capability. And if you do that, if you're able to get

1 electric vehicles and actually electrify other parts of the
2 system, as we'll talk about a little bit later, you can
3 actually leverage that to decarbonize other sectors. And
4 then once you decarbonize other sectors, you can actually
5 use those resources to actually help the grid going forward.

6 And then there's just general flexibility,
7 flexible resources, having resources being responsive. And
8 I'm not just talking about conventional resources that we
9 traditionally think of flexibility. I'm talking about the
10 new resources, about renewables providing some of that
11 flexibility, those grid services, storage providing some of
12 that flexibility, demand providing some of that flexibility.

13 Just a couple areas I wanted to dig a little
14 deeper into in terms of the Western Energy Imbalance Market.
15 We had started that about two-and-a-half years ago. We're
16 now -- we've measured benefits of about \$173 million of
17 efficient economic benefits of the EIM. We've got broader
18 participation. And every day or every month it seems like
19 we see additional entities that want to participate in the
20 Energy Imbalance Market. The Energy Imbalance Market now is
21 approaching almost 50 percent of the load across the west is
22 within a balancing area that's within the Energy Imbalance
23 Market.

24 So we're very excited about this. And we see this
25 as a continued evolution and support for integrating

1 additional renewables.

2 The Energy Imbalance Market is not just a
3 financial benefit, but it also helps -- we talked about the
4 curtailment, and we see potential increased curtailment. We
5 see the Energy Imbalance Market by being able to consume
6 some of that energy, displace resources in other parts of
7 the west at times when we have additional supply. And we're
8 seeing the increased avoidance of curtailment by use of the
9 Energy Imbalance Market. That's represented by the red bars
10 in this graph. And the gold line is basically the
11 accumulative amount of avoided curtailment.

12 When we talk about flexibility we think about,
13 well, resources in the system. And what we need to start
14 looking at balance is what's really moving to balance the
15 system during these ramping events? So we looked at the
16 sample day of April 23rd. And what's interesting is it's
17 not gas resources, much as I thought it was. Actually,
18 interties, getting energy, not through the Energy Imbalance
19 Market, okay, this is interties that are actually shaped
20 through the day-ahead market, are largely providing a
21 significant portion of the ramping needs into the evening
22 hours. Gas provided 37 percent of the ramp on this
23 particular day. And hydro, even though we're in over --
24 even though we've in high hydro conditions, we still are
25 able to get some flexibility, some dispatchability. It

1 provided almost 20 percent of the ramp over the evening
2 ramp.

3 If we looked a little deeper of what resources are
4 providing flexibility, we also see opportunity for getting
5 more flexibility, real-time flexibility. Not surprisingly,
6 we see from this graph, and what you're seeing here is the
7 green bar is the amount of bid-in capacity that is bid in,
8 in real-time. By being bid-in it provides us, the market
9 operator, the ability to dispatch that resource to meet the
10 flexibility needs of the system.

11 The blue bars are effectively the amount of
12 capacity that's not bid in, self-scheduled. And that
13 capacity, we don't have the ability to move and flex to
14 balance the system.

15 So if we look across here, and this is a picture
16 in time from 2016, is we can see the expectation that
17 natural gas is providing a lot of the flexibility, as we
18 expected. But if you look across you quickly get to see
19 that we're seeing increasing amounts of flexibility, bid-in
20 flexibility from hydro, solar, even some geothermal, and
21 wind resources. But there's also opportunity there.

22 You can see that there's a significant amount of
23 blue bar, which indicates that there's still more
24 flexibility that can be achieved and provided if the
25 incentives are right on these resources. Now in some cases

1 you're going to get into technological limitations on some
2 of the older resources. But we believe that most of the
3 newer resources, at least if they're designed going forward,
4 we can design these resources to be flexible and provide the
5 flexibility.

6 If we continue to move to the right we see the big
7 bar of imports. So in contrast to my previous aside where I
8 said the imports are actually providing a good portion of
9 the evening ramp, they're not providing real-time
10 flexibility. So they're getting shaped, they're meeting
11 somewhere on the ramp, but we're not able to tune them, do
12 the fine tuning and balancing with those imports because
13 very little of those imports are being offered into real-
14 time, and that's an opportunity. If we can get those
15 imports and exports bid in so that we can dispatch those
16 more dynamically in real-time, that would be an advantage
17 and would reduce our reliance on other forms of flexibility.

18 The Energy Imbalance Market is one that's doing
19 that. But we can see that there is a large opportunity, if
20 we can navigate this, to make the imports a more flexible
21 dynamic resource for system operations.

22 Nuclear, I'm not going to talk too much about
23 that. It's not a flexible resource. We understand that.
24 And by 2024, the remaining nuclear resource will be retired,
25 actually making room for and helping to actually manage and

1 reduce the oversupply condition.

2 This slide is speaking to time-of-use rates. And
3 this is something that we've been using in discussions at
4 the CPUC about time-of-use rates. And what we're trying to
5 do with this graph is try to align and take kind of the duck
6 shape or the net load shape and kind of highlight that we
7 need, if we're going to move into time-of-use rates, we need
8 the time-of-use rates periods to be designed to coincide and
9 align with the system conditions.

10 And so what we've been advocating for through
11 these graphs is that there are periods of time that you're
12 going to have a large amount of or a deep, low net load.
13 And during those times in the middle of the day, we believe
14 that there's a need for a rate structure that indicates,
15 believe it not, in the middle of the day, you need to
16 increase load, potentially, if you can. And that's -- that
17 would be helpful when we get into those negative price
18 conditions.

19 Energy storage. We've been looking at energy
20 storage for quite a while. And let's be honest, energy
21 storage is a challenge. We've been looking at bulk storage.
22 It's a large capital investment. And even battery storage
23 is still a large cost, even though you can break it up into
24 smaller parts.

25 The interesting thing with energy storage is it

1 provides multiple value propositions. One of the value
2 propositions is just being able to arbitrage prices. So if
3 you can store when prices are low and then produce when
4 prices are high, that's a market revenue stream for those
5 resources. But there's other value streams to storage
6 resources, carbon reduction, managing the renewable
7 overbuild. What I mean by renewable overbuild is that when
8 we get into these higher levels of renewables and we are
9 starting to have to curtail the renewables, we have to, if
10 we're going to meet our targets, we've got to bring more and
11 build more to make up for the lost energy, so we have to
12 build more capacity, so there's a cost of that overbuild.
13 If we can store it, rather than losing that opportunity we
14 could reduce those overbuild costs, and that's what this is,
15 that's what the yellow bar is expressing.

16 And then there's just general production cost
17 benefits because these resources can provide a variety of
18 services, energy stored up, ancillary services. And so the
19 point is that these graphs are still -- is illustrating that
20 the multi-value proposition needs to be looked at. And at
21 some point, even though these graphs don't indicate that
22 it's reaching the levelized revenue requirement of the
23 resources, we believe that at some point in the spectrum of
24 going to 50 percent and beyond 50 percent, or the costs
25 coming down in the case of batteries, that this, the multi-

1 value proposition, will indeed surpass the cost of the
2 resources.

3 I know this is a bit of a complicated graph, but
4 these were the studies that we did in a part of our
5 Transmission Planning Study, special study work. We did it
6 at 50 percent, and we studied both a 500 megawatt and a
7 1,400 megawatt bulk storage resource. And the green bars
8 are basically the levelized revenue requirement. The bars
9 next to them are stacked to value propositions of the value
10 areas that I indicated earlier.

11 This work is continuing. We're continuing to
12 evolve this work. This is actually a little bit of an
13 update from our transmission planning work. We're
14 continuing to do additional scenarios, looking towards the
15 future.

16 Distributed energy resources is another area of
17 solution. As we get more and more distributed resources, we
18 should be seeking to have these distributed resources not
19 just provide energy, but provide services to the system.
20 And so that results in the need for having a coordination
21 and a visibility and a controllability, at least an
22 aggregate, of these distributed energy resources. And later
23 today another -- Peter Klauer from the ISO will be
24 discussing, I think, distributed energy resources with you,
25 so I won't go into any more on that at this point.

1 In terms of electric vehicles, this graph is just
2 to kind of illustrate that depending on the duck shape -- or
3 depending on the shape of the charging, and in this case
4 this is electric vehicle home and workplace charging, you
5 can see that in the middle of the day it actually is
6 potentially helping because they maybe can be able to bring
7 up the belly of the duck. But when people get home, you
8 still have that possibility that you're going to have the
9 highest charging rate, which may actually increase the
10 evening load at the same time when the load is peaking.

11 So the point is, is that the electric vehicles are
12 an opportunity, but we need to find a way to align the
13 charging and incentivize the charging at the right time if
14 we're going to get those resources -- or get those new
15 electric vehicles to actually help manage some of the grid
16 net load shape in the balancing.

17 So in closing here, I think really it's kind of
18 echoing Tom's opening message, this is a long game. This is
19 the point at which we are now seeing the renewable growth
20 and we're going to see continued renewable growth, and it's
21 now started to leverage the dividends on our investments.
22 We spent millions of dollars on these renewables. Now, we
23 need to find a way to do the most with the renewables, not
24 just for getting the electricity themselves, but also the
25 things that that electricity can do by electrifying other

1 parts of the economy, whether it be electric vehicles or
2 industrial processes or heating and cooling.

3 If we can do that, it kind of leads us to the
4 point where you really want to be, and that is you've
5 decarbonized the electric grid, but you've also moved to a
6 point where you're decarbonizing the other sectors. And
7 this kind of circle, we call it the circle of life, but the
8 carbon circle is that where we are today, if we can now use
9 the electric grid and the decarbonizing properties to
10 decarbonize other sectors, decentralize supply, we can then
11 have not just a decarbonized other sectors, but those other
12 sectors now have properties that they can use to help the
13 grid reliability -- electric vehicles, heating and cooling.

14 If we can get those other decarbonized sectors to now
15 provide grid services, then we actually can leverage that to
16 bring it back into a grid control that relies less on carbon
17 resources for balancing and grid reliability.

18 So this is a long game. This is going to take
19 several years. But how we do this, whether it be through
20 the Integrated Resource Plan, or how we develop some
21 innovative technologies, now is the time to think about this
22 and the full cycle of what we can do with the resources and
23 what we do with them.

24 And with that, I want to thank you.

25 I do want to put -- I know I have an appendix

1 here, but I'm not going to go through all the slides. I do
2 want to do one thing. I just want to remind everybody that
3 we're coming up on a solar eclipse. This is August 21st and
4 it's a summer day. It's a Monday. And I wanted to give you
5 some insights about what, during the solar eclipse, what is
6 going to happen.

7 So the solar eclipse, the full eclipse, is going
8 to be north of California. So in terms of the amount of
9 solar loss, we're in the range of about 60 to 70 percent
10 solar loss as a result of the solar eclipse on that day. It
11 will be -- it's roughly a three-hour event, starting roughly
12 around nine o'clock and ending about noon. And so in that
13 morning load pull we basically will lose about 5,600
14 megawatts of solar production as a result of the solar
15 event. We'll ramp that back in from about ten o'clock to
16 noon, returning probably just about 6,000 megawatts over a
17 one-and-a-half-hour period. So basically, it results in
18 about a 100 megawatt per minute ramp of the solar as the
19 solar comes back.

20 So Europe went through this. They survived. I'm
21 not saying that we're going to have significant issues, but
22 we are planning for this. And some of the planning will go
23 into some of the things that we may have to carry some
24 additional regulation, we may have to carry some additional
25 reserves for this time. We may have to pre-ramp or pre-

1 curtail some resources to temper the ramp if we feel like
2 we're not going to be able to take the ramping burden during
3 that time.

4 So we're preparing for this. We're forecasting
5 for this. We've prepared a little report. And when this is
6 over, we'll prepare a report on how we went through this,
7 because it's not the last solar eclipse. We'll have other
8 solar eclipses in the future, and we'll probably be at
9 higher levels of solar at that point. So let's take this
10 opportunity to learn from it and apply it for what we can do
11 going forward.

12 And with that, I'll take any questions.

13 CHAIR WEISENMILLER: Yeah. A couple questions,
14 Mark.

15 I mean, the first question is just I guess the
16 bottom line question. And in terms of the reliability of
17 the California system at this point, has there been any
18 impact from the level of renewables we have?

19 MR. ROTHLEDER: Yeah. I mean, I mentioned earlier
20 that we're having -- we're taking more effort -- it's taking
21 more effort. We have to bring more resources on for
22 regulation to meet our control performance standard. If we
23 didn't do that, we would potentially be at risk of not
24 meeting that standard and be subject to fines.

25 I will say we had a Stage 1 event last week. And

1 one question that I'm sure people are asking, well, what
2 caused that event? We're still analyzing that. But I will
3 say that part of the contributing effect during that Stage 1
4 event, not the sole event, but one of the contributing
5 things was that that evening ramp was so steep at a time
6 when we were already in stress conditions, we effectively
7 lost through the ramp, even though it's predicted, about
8 1,500 megawatts from what we had scheduled on an hourly
9 basis day ahead, forecast on a day-ahead basis.

10 In the middle of that ramp, in the middle of the
11 hour, we lost as much as 1,500 megawatts just because of the
12 solar ramp out. That's at a time when we were already in
13 stress conditions because there was already a missed
14 forecast. Some resources were unavailable that were
15 anticipated to be available, so we were already in tight
16 conditions. That extra 1,500 megawatts helped throw us over
17 to the point where we were not maintaining our operating
18 reserves. And as a result of that we had to call a Stage 1
19 in order replenish our reserves, called demand response at
20 the point.

21 So that is an event and it's not -- if you talk to
22 our operators, they'll say these types of events, these
23 types of events where frequency is getting harder and harder
24 to maintain in the needed levels, it's getting harder and
25 harder to do that. Now we're trying to work with them to

1 provide additional tools with a flexible ramping product,
2 setting up additional regulation. But they are seeing the
3 effect of this variability.

4 CHAIR WEISENMILLER: Okay. But getting back to
5 the fundamental question, the NERC Reliability Standards,
6 would you say CPS1 is the most important one, or which
7 would -- what would be the standards we have to look at?

8 MR. ROTHLEDER: So the CPS1, there's BALL, which
9 is kind of measuring frequency, as well. There's --
10 obviously, you can't overload your lines. There's the
11 frequency response standard that if you have an event, you
12 have to return your frequency within a certain period of
13 time. That's relatively new. And we have to carry enough
14 frequency response capability to do that. If you have
15 high -- or if you have low loads, high renewables, a lot of
16 your frequency response capability has now been turned off.
17 And so we need to find new ways of getting that frequency
18 response capability, either from those resources that are
19 now on the system or, unfortunately, if we don't do that
20 we're going to have maintain other resources on just for
21 frequency capability. And maybe Clyde, when he gets on with
22 his part of the discussion --

23 CHAIR WEISENMILLER: Right.

24 MR. ROTHLEDER: -- he can elaborate on this.

25 CHAIR WEISENMILLER: Yeah. But I think the

1 fundamental thing I'm trying to get to is that while we've
2 had to take mitigation measures such as having more
3 resources available, that we are maintaining the reliability
4 of the grid.

5 MR. ROTHLEDER: Yeah. Ultimately, I mean, we are.
6 We're maintaining the reliability of the grid. There's no
7 doubt about that. And we will take every measure to do so
8 in the future. At the same time, we will continue to study
9 to see if we are getting into critical areas that we need to
10 do anything more extraordinary or add new products or
11 capabilities.

12 CHAIR WEISENMILLER: Right. I would say the other
13 thing I would note, that curtailment is not unusual. In
14 China, again, we're looking at their grid, they have periods
15 where their curtailment renewable was 40 percent. The
16 German's have less of an issue, but that's because they're
17 connected into the European grid on more of a regional
18 market. I think Reiner Baake always says they can store in
19 the grid excess generation.

20 MR. ROTHLEDER: Yes.

21 COMMISSIONER RANDOLPH: I have a quick question.
22 On the slide, when you were talking about imports --

23 MR. ROTHLEDER: Yes.

24 COMMISSIONER RANDOLPH: -- you were talking about
25 ways to make imports more flexible, EIM being one solution.

1 And what are you talking -- so for other solutions are you
2 talking about creating new products, or what do you mean
3 when you talk about --

4 MR. ROTHLEDER: Yeah.

5 COMMISSIONER RANDOLPH: -- ways to make it more
6 flexibility?

7 MR. ROTHLEDER: I think there's some ideas you'll
8 be hearing from some of them this afternoon. But there's
9 been proposals of, for example, WSGP, they kind of define
10 the contractual product. And they are working on or they
11 developed not just a block product, but they've actually
12 developed a product that in a way is the counter shape to
13 the duck curve. So in other words, you get some energy in
14 the morning, you get some energy in the evening, but the
15 midday, you don't get the energy. And if you can shape that
16 product, it basically provides you some counter shaping to
17 the duck curve. So there's those types of innovative things
18 that are being looked upon, even in the bilateral world of
19 trying to develop things that are helpful in navigating and
20 reshaping the system conditions.

21 MR. DOUGHTY: There I wanted to just offer an
22 observation. For those of us who are getting long in the
23 tooth like me, you look back on the history of this industry
24 and it looks so simple compared to what we have today. I
25 remember when we would deploy capacity to expand the grid.

1 And now the expansion of the grid is built around
2 capability, flexibility.

3 Our operators now tell us that they're no longer
4 challenged by a hot August afternoon as much as they are by
5 a cool and periodically breezy and periodically sunny March
6 afternoon. The fluctuations we see in renewable production,
7 both wind and solar, during those periods are untested.
8 We're just now learning how to do that.

9 So to Mark's point, we are maintaining
10 reliability. But there is a new level of difficulty in
11 doing so, just because of these new variables that hadn't
12 challenged us before.

13 CHAIR WEISENMILLER: Thanks again.

14 Let's go on to the next presentation.

15 MR. ROTHLEDER: Thank you.

16 MS. RAITT: Thanks, Mark.

17 Next is Clyde Loutan, also from the California
18 ISO.

19 MR. LOUTAN: Good morning. Good morning. So my
20 presentation is going to be surrounding how can we use
21 renewables to balance the grid?

22 So about a little over two years ago the North
23 American Electric Reliability Council formed this task
24 force. And the objective of this task force was to identify
25 the essential reliability services that's needed to

1 integrate higher and higher levels of renewables. So we
2 started, then we started to think, well, what would it take
3 to integrate, you know, more and more renewables into the
4 grid?

5 So the first thing that came up was voltage
6 support. The second thing we thought about was frequency.
7 Then luckily out west, we started to see the need for
8 flexibility with the amount of solar that was going in. So
9 we were able to get flexibility, but not to realize flexible
10 capacity as a requirement to integrate higher and higher
11 levels of renewables.

12 So with those three things, when the opportunity
13 came to test this solar plant, we kind of tailored the tests
14 to look at flexibility of ramping needs, voltage control,
15 frequency control. So there's a fairly large, a 300
16 megawatt solar plant. We teamed with First Solar, NREL, we
17 developed this test plan, and we started testing this unit.

18 Now as Mark mentioned, you know, with solar
19 plants, even wind plants, we got over 10,000 megawatts of
20 existing transmission connected solar. A lot of those are
21 not controllable today. So they trip offline, the sun is
22 still shining, they could come back on in seconds. They can
23 trip off in seconds, also.

24 So one of the things we wanted to see, well, can a
25 solar plant mimic ramp rate?

1 So the first test we looked at was taking this
2 plant from 280 megawatts down to zero, back up to 250
3 megawatts, given ramp rates. So we chose 30 megawatts a
4 minute which was really ten percent of the pMaX on this
5 unit. And the red curve here is really the set points that
6 we set ahead of time. We fed this into the solar plant.
7 And as you can see, the solar plant was able to ramp down at
8 30 megawatts a minute from 280 megawatts down to zero and
9 back up to 250 megawatts. And it was able to follow those
10 signals fairly well, so this was pretty encouraging.

11 The second thing that we looked at was how well
12 can this plant follow a four-second regulation signal. So
13 the plant, we tested this three times during the course of
14 the day. The first test was during sunrise. And this graph
15 here is really during sunrise. So the green curve is really
16 the maximum capability of this plant at any given point in
17 time. We backed this plant off 30 megawatts. And then we
18 fed this plant an actual four-second signal. So as Mark --
19 most of his presentation covered a five minute dispatch, but
20 we also control the system every four seconds to maintain
21 that balance between the generation and the load.

22 So you might think four seconds is pretty fast,
23 but four seconds is pretty slow when you think about the
24 speed of electricity. So the speed of electricity, you
25 know, 186,000 miles a second, we control this every four

1 seconds. And to put it in perspective, if you think about
2 driving down the freeway at 60 miles an hour with the eyes
3 closed and every four seconds you open your eyes to see
4 where you're going, now think about a windy road. And this
5 is essentially what we do, try to monitor the system on a
6 four-second basis. That's pretty slow when it comes to
7 electricity.

8 So if you look really closely you can see those
9 red -- there's a red curve in there. And as I said, this is
10 the actual four-second signal we fed into a plant, a
11 combined-cycle plant. We fed the same signal into this PV
12 plant. And you look at the yellow curve, this plant was
13 able to follow that curve very well. So again, this was
14 very encouraging to see how this plant was able to follow a
15 four-second signal.

16 We did some comparison. When you look at the
17 existing fleet and you look at the steam turbines that we
18 have on today, they can follow a four-second signal about 40
19 percent accuracy. So when we pay for things like the
20 regulation service, they get paid for a capacity, a whole
21 (indiscernible) capacity, and then how well they can follow
22 that four-second signal. When you look at combined-cycle
23 plants, you know, it's a little less than 50 percent. And
24 then the gas turbines are about 63 percent. In this test
25 this solar plant was able to follow that four-second

1 regulation signal anywhere from 87 percent to 94 percent,
2 which was very encouraging. That's really, really good.

3 Now the second thing we wanted to test was voltage
4 control. On this plot, if you concentrate on the blue and
5 red curve, you can see, what we did is we fed this plant
6 different reactive levels; right? So when you think about
7 the grid, the grid voltage swings quite a lot during the
8 course of any operating day. So when the system peaks the
9 voltage tends to be low. During off-peak the voltage tends
10 to be high. And with the amount of conventional use we've
11 had in the past, they were able to help control the
12 voltages. Now what we started to see, like on weekends the
13 voltage tends to go high because you have a lot of renewables
14 in the system, the load is low. You do not have a lot of
15 conventional units to help you control the system voltage.

16 So this tells you, we wanted to see how well this
17 plant could control voltages. So what we do is we hold
18 schedule voltages at key substations within the California
19 ISO's footprint. And so by holding these voltages these
20 plants can move their reactive output, either take in
21 reactive if the voltages are too high or put out reactive
22 power if the voltage is too low.

23 So we were able to take this plant -- so if you
24 think about the reactive capability on any resource, it's
25 roughly about one-third the capacity. So this plant is a

1 300 megawatt plant. You'd realistically expect to get about
2 100 MegaVARs out, 100 MegaVARs in. And so when you look at
3 what this plant was able to do, if you look at the green
4 curve now, is we were able to swing the 230,000 voltage
5 anywhere from 227 kV to 242, which was, you know, pretty
6 impressive.

7 The second thing about this plant is if you think
8 about a V, what FERC said when FERC came out with the
9 voltage requirement, on asynchronous resources, they set a
10 maximum amount per unit to get maximum reactive. So now
11 there was 300 megawatts, the expectation is this plant
12 should be able to provide 100 MegaVARs in, and take in 100
13 MegaVARs to support voltages. And at 50 percent output, or
14 about 150 megawatts out, the expectation is half the amount
15 needs to be in reactive, so you get 50 MegaVARs out, 50
16 MegaVARs in. Then if it's less than ten percent of the pMax
17 the expectation is there's no reactive output.

18 Well, we were able to take this plant from 280
19 megawatts all the way down to 5 megawatts. What this plot
20 shows is this plant was able to provide full reactive. So
21 we were able to get 100 MegaVARs out at 5 megawatts, which
22 was unbelievable. And this plant was able to take in 100
23 MegaVARs to help support the voltage.

24 Now the other thing that this plot tells us is at
25 5 megawatts, this plant could really operate at night. So

1 at night this plant could take 5 megawatts off the grid, or
2 even less, and help you provide voltage support. So this,
3 again, you know, surprised us during the course of this
4 test.

5 The other thing we tested for, and Mark alluded to
6 this, is frequency response. So frequency control is one
7 thing. We try to control the system frequency every four
8 seconds. Then we have the CPS1 benchmark that we look at.
9 And again, you know, what we started doing at the California
10 ISO is evaluating the system every minute, we look at how
11 well we perform every hour, so we can see what challenges
12 started to show up so we could correct that.

13 This is a yearly benchmark, so we look at 12
14 months rolling average, and typically we're above 100
15 percent. But by looking at the system performance on an
16 hourly basis, we can tell what challenges show up.

17 So this plot here shows you the actual frequency
18 when we lost a big load in the west. So we fed this signal
19 into this plant. And if you look at just 200 seconds, the
20 yellow is really what this plant was able to do. So this
21 plant was able to -- the system frequency went high, the
22 plant output dropped off. And when the system frequency
23 came back down to 60 cycles, the plant output, you know,
24 again started to go back up. So again, this plant was able
25 to follow this frequency signal very well.

1 The other thing about the solar plant is there's
2 something we call a droop setting on this plant. So during
3 this test we wanted to say, well, if this -- can this plant
4 mimic a hydro plant. So we changed the droop setting on
5 this plant. And as you can see, the response here is
6 similar to our hydro plant.

7 So the second test we did, we looked at a low-
8 frequency event. So here, this was an actual event we had
9 in the west. We lost 800 megawatts. And we wanted to see
10 how well this plant can follow this frequency signal. And
11 we said, well, how about if we mimic this plant to be, let's
12 say, a combined-cycle plant? And so we changed the droop
13 setting on this plant. And as you can see, this plant was
14 able to respond very, very quickly to the frequency event.
15 And as the frequency recovered to 60 cycles, the plant
16 output decreased.

17 So again, these tests really showed us that the
18 newer solar plants, and later on this year we're going to
19 test a wind plant, they can provide the central, reliable
20 services that we need to control the grid.

21 So with that we started, you know, sharing the
22 results. A lot of folks are pretty interested in the
23 results of this test. And again, this was the largest test
24 of its kind that was done in the world. About three weeks
25 ago we presented this internationally, we had a webcast, and

1 we had folks, 250 folks from throughout the world, listening
2 in to the results of this test. We also plan to explore
3 further opportunities where renewable resources can
4 participate in the various markets that we have today. I
5 hope they can also provide ancillary services.

6 Now with that, I'll open up for any questions you
7 may have.

8 CHAIR WEISENMILLER: Yeah. The one question I had
9 was ERCOT last year did a study on inertia. Has the ISO
10 done any studies on inertia, or could this in any way help
11 on the inertia situation?

12 MR. LOUTAN: So the response, yeah, it could
13 definitely help in inertia. Now NREL and GE did a study
14 through WWSIS last year. And one of their conclusions is
15 the WWSIS, right now inertia is not really a problem;
16 frequency response is a problem. So when we talk about
17 inertia, it's really within the first 8 to 12 seconds
18 following the service (phonetic) on the grid, is that
19 frequency going to decline really fast to hit the first
20 level of relay (phonetic), so we start tripping load at
21 59.5. So what they found out is in the near future that
22 inertia is not going to be a problem. If it does, let's
23 say, more and more states develop RPS goals, now we know
24 that the solar plants can help us provide this boost of
25 energy within seconds. Actually, they can do it in cycles,

1 so we can mimic the inertia response.

2 The other thing that they're doing in ERCOT that's
3 pretty interesting, too, is they trip about 1,400 megawatts
4 of load in half a cycle, so that helps with the inertia
5 problem.

6 So if inertia become a problem within the ISO or
7 within the WESS, we think we have ways to mitigate that.

8 CHAIR WEISENMILLER: That's good. Actually, I was
9 going to say, we have ERCOT on the next -- on one of the
10 future panels, so I know the speaker will be able to discuss
11 more their study results.

12 COMMISSIONER MCALLISTER: So this is purely
13 electronic control; right?

14 MR. LOUTAN: Yes.

15 COMMISSIONER MCALLISTER: Are there any weaknesses
16 that you, you know, that you do see or any uncertainties
17 that you still have, like what directions and what are the
18 future tests going to try to, you know, look at? I mean, it
19 sounds like you're getting pretty comfortable with being
20 able to, you know, electronically control the power in a way
21 that mimics -- you know, that does what you need it to do,
22 so --

23 MR. LOUTAN: So one of the concerns is, like Mark
24 alluded to this, is the forecasting. So if you -- let's say
25 you want this plant to provide upward regulation service,

1 then you've got to really make sure that you know how much
2 headroom you have, or capacity, that you can move out. What
3 we found out is sometimes it's easy to predict, you know,
4 the cloud movement. But I if you have a hole in that cloud,
5 it really makes it more and more difficult to forecast the
6 output of that plant.

7 And then during sunset, that's another challenge.
8 If this -- if you want this unit to provide upward service,
9 you've got to make sure that we know exactly how fast that
10 solar is ramping down. And on cloudy days, it could be, you
11 know, very difficult.

12 COMMISSIONER MCALLISTER: So it's really just kind
13 of dealing with the noise in this system when you have these
14 marginal conditions?

15 MR. LOUTAN: Yes. And a lot of research is going
16 on right now, especially, you know, I know First Solar is
17 doing a lot of work trying to figure out exactly how much
18 capacity they think the plant can produce at any given point
19 in time.

20 COMMISSIONER MCALLISTER: Yeah. Yeah.

21 MR. LOUTAN: The other thing that we needed to --
22 remember, back in March of this year, we had some
23 consecutive days where we had no sun. You know, it was
24 windy, it was gusty. And so I think I'm very optimistic,
25 but we've got to be cautious, too, cautiously optimistic.

1 COMMISSIONER MCALLISTER: Okay. Thank you.

2 MR. ROTHLEDER: If I could just add to that, that
3 the downward flexibility is a little bit easier because, I
4 mean, where we are producing, you can flex down. The upper
5 flexibility, especially if you're using for a reserve
6 service, this notion of how much you can rely upon in this
7 changing forecast and variability is very different from how
8 we view our typical reserve resources, because we have a
9 static pMaX and we know how much we can get from it, and we
10 have confidence about it. So we have to build in a level of
11 uncertainty about the reserves itself at that point.

12 CHAIR WEISENMILLER: Thank you.

13 MS. RAITT: Thank you. Our next speaker is Ed
14 Randolph from the California Public Utilities Commission.

15 MR. RANDOLPH: Thank you, Heather.

16 Good morning. As Heather said, I'm Edward
17 Randolph. I'm Director of the Energy Division at the
18 California Public Utilities Commission.

19 We've heard from our first two panelists, and I
20 think we'll hear from a number of panelists throughout the
21 day, a number of technical solutions to some problems that
22 Mark identified early on in terms of need for more flexible
23 resources as we go forward.

24
25 What I'd like to spend some time talking about is

1 the regulatory solution or the regulatory roadmap on how we
2 get to some of these technical solutions and put them
3 together. And I think it's worth starting out by spending a
4 brief moment talking about the current planning process at
5 the Public Utilities Commission.

6 And we do have a planning process now that looks
7 at both long-term and short-term needs. The planning
8 process looks at the need for multiple capacity needs,
9 system capacity, local capacity, and flexible capacity. We
10 do that both through our long-term procurement planning
11 proceedings, or historically we've done that through that.

12 And we do the more short-term needs through our
13 resource adequacy proceedings. Our resource adequacy
14 requirements do require flexible capacity now for our
15 regulatory entities to procure. That flexible capacity is
16 defined by what the CAISO has defined as their needs, and it
17 carries over into ours. As the CAISO changes or refines the
18 needs for flexible capacity, our RA requirements would move
19 to address that.

20 In anticipation on some conversations that may
21 come up this afternoon, it's worth noting that in our
22 current RA confines there are long-term contracts. You will
23 hear people say we need longer RA contracts for various
24 reasons. Our rules do allow for longer contracts and they
25 do, in fact, exist. The utilities signed them on a

1 bilateral need based on the value and the needs that they
2 see there.

3 And another thing to note, both looking at short-
4 term and longer-term planning needs, you know, is that as we
5 get to more specific definitions of what a flexible need is,
6 that can lead to more market-driven contracting activities
7 for those flexible needs, beyond what we have now. It's
8 much more of a you get what you measure and you get what you
9 value.

10 Shifting forward, though, to integrated
11 (indiscernible) the process we're now developing, the
12 process required out of SB 350 is the integrated resources
13 planning process. The comparison of this to the old process
14 and how this relates to how we can better incorporate
15 flexible resources is the integrated resource planning
16 process is much more of an optimization process.

17 The historic long-term procurement planning
18 process at the PUC is really a siloed approach to
19 procurement. And by siloed approach what I mean is the
20 procurement of most of our preferred resources are clean
21 resources, are based on targets that were set independently
22 of each other, set either by statute or set by program goals
23 within the various resource proceedings at the Public
24 Utilities Commission. However, most of those resources are
25 not looked at together to see what the optimum mix is. And

1 what LTPP historically did is take those individual siloed
2 goals, put them together, and solve for the remainder need
3 to ensure reliability. That has probably led to some
4 perverse outcomes where we're getting more of one resource
5 than we need, or spending more money on a resource where
6 there may have been a more cost-effective option.

7 And that gets us to the integrated resource
8 planning process, which, as I've said, it's an exercise in
9 optimization. It will look to find an optimal mix of
10 supply- and demand-side resources over the long-term. At
11 this point we're looking at that as a 20-year mix. It's key
12 focus, which will be the first time in the PUCs procurement
13 that we're directly looking at greenhouse gases emissions,
14 so its key focus is greenhouse gases emissions based on
15 targets, while maintaining grid reliability at the lowest
16 possible cost. And that modeling that we'll do within there
17 will identify or can identify a portfolio of resources to
18 meet, you know, to meet the policy and grid operational
19 constraints.

20 Key inputs into this going forward, we'll start
21 with demand and load shapes that come from the CEC's IEPR
22 demand forecast, the existing fleet of resources out there,
23 including incorporating in planned retirements out there,
24 that's mainly the once-through cooling plant retirements,
25 and the existing resource mandates that are out there, such

1 as the 50 percent RPS mandate and the doubling of energy
2 efficiency requirement from SB 350.

3 And then from there you can optimize the resource
4 mix out there to help address the integration of renewables
5 and help get that mix of flexibility that you're looking at.

6 And you're optimizing renewables, storage, demand response,
7 thermal generation. And at the end we can run sensitivities
8 to look at how if you pulled different levers differently,
9 if you add more energy efficiency or have more demand
10 response, or we want more or less electric vehicle
11 assumptions, how that changes the overall mix and how that
12 changes the cost-benefit equation for the end-use consumers.
13 And at the end of the day the procurement can be and will be
14 informed by the modeling that goes through this process.

15 The statutory basis for IRP, as I said, this is
16 mandated through SB 350. SB 350 added two sections to the
17 Resources Code. The first section specifically requires us
18 to identify a diverse and balanced portfolio. And the
19 second section, 454.52, adopt a process for all loads
20 serving entities to file an Integrated Resource Plan to
21 ensure that load-servicing entities do the following. And
22 noting that this is what applies, the code sections apply to
23 our jurisdictional entities, the PUC. There are similar
24 code sections that apply for publicly-owned utilities under
25 the jurisdiction -- or under the oversight of the Energy

1 Commission.

2 I'm not going to go through this list of goals
3 here that are mandated in statute, but hit a few key ones.
4 Again, we get what we measure. Our ultimate goal in
5 California is the greenhouse gases reduction targets, that
6 is the first goal of IRP, continuing to achieve the RPS
7 targets, minimizing impact on ratepayer bills, you know, and
8 so forth down the list.

9 The schedule for IRP, this is kind of the exciting
10 time there. If you're an energy nerd, I think IRP is just
11 getting to that point right now that it's going to be really
12 exciting for the next couple of months.

13 Next week, we should be releasing a staff proposal
14 on the process for the IRP for load-serving entities under
15 the PUC process. And then in June, we will be releasing
16 modeling results for the electricity sector to reach GHG
17 emission targets.

18 A little bit of a preview on what will be in the
19 staff proposal coming out next week, a high-level preview.
20 The staff proposal proposes, you know, first initially
21 setting greenhouse planning targets based on the ARB's
22 Climate Scoping Plan targets. From there the PUC would
23 model and establish a reference system plan. This is a
24 modeled optimized portfolio meeting the greenhouse gas
25 targets at end reliability at lowest ratepayer cost. That

1 reference plan would also evaluate opportunities and impacts
2 for disadvantaged communities, and would have an output of a
3 marginal GHG abatements' costs to use in resource valuation.

4 From there the LSEs, under our jurisdiction, would
5 all -- would individual be asked to develop a responsive
6 portfolio on their own, but use their knowledge of their
7 needs and their resource capabilities. Those individual
8 resource plans would be compared back against the reference
9 plan when they're submitted back to the CPUC. And the CPUC
10 would aggregate those plans to make sure we're meeting the
11 system goals, and use that as the basis on any procurement
12 decision making that needs to be made on a system-wide
13 basis, and potentially on the individual LSEs.

14 Just a note there about setting GHG planning
15 targets for the IRP. The statute requires the ARB to set
16 the targets for the electricity sector, and for the
17 individual LSEs for the IRP process. The statute also says
18 that's in coordination with the CPUC and the Energy
19 Commission. That coordination started long ago through a
20 series of meetings, workshops. We've had lots of
21 conversation on how those targets will be set and how
22 they'll be established to the load-serving entities.

23 In the interest of time, I will move forward,
24 though.

25 And another key point of the IRP is the

1 interagency coordination. I think with almost all things
2 clean energy and climate related is an unprecedented level
3 of interagency coordination that's required now. And my
4 personal belief is the agencies are working better together
5 now than they ever have before, but IRP is one more place
6 where we all have to work together. The CEC will need to
7 set integrated resource planning for the POU's, which needs
8 to be coordinated with the integrated resource planning that
9 the PUC is working on.

10 Additionally, all the integrated resource planning
11 is highly dependent on the demand forecasts that come out of
12 the CEC. All of this is very dependent on the ARB's Scoping
13 Plan updates, and will be dependent on how cap and trade
14 compliance obligations are set in the future. And of
15 course, none of this works without the ISO's transmission
16 planning process. And they're own resource adequacy
17 obligations and coordination with us, so, I mean, from
18 operational conditions today to a preferred resource plan.

19 The IRP is the first opportunity for California to
20 look at a potential path from today's operational conditions
21 to a resource mix that achieves the SB 350 and the SB 32
22 goals. This is the first time, as I've said before, that
23 we're doing this optimization where we're specifically
24 solving for those AB 32 goals out there. And as I've also
25 said before, you get what you measure. If we want to get to

1 those goals we need to specifically be targeting those goals
2 and measuring for those goals. Reliability and GHG emission
3 reductions are going to have to be optimized in order to
4 achieve these goals in the least cost.

5 A number of the technical solutions, we're going
6 to talk about later today, they'll all help solve these
7 problems. But we know from looking at modeling already that
8 unless you look at all of them in total and model them
9 against each other, we won't get there at a least-cost
10 basis.

11 And what we already know, we already know to reach
12 the SB 350 and the SB 32 goals, that's going to require 100
13 percent achievement of the mandates that are already in
14 place. That's the doubling of the energy efficiency, the 50
15 percent RPS, demand response goals that have been set by the
16 agencies, the zero-emission vehicle goals, and the energy
17 storage goals out there. So nothing in an IRP actually
18 would be a backing away of the current goals. Actually,
19 we'll be accelerating some of those goals.

20 We also know the IRP process needs a chance to
21 work. We need to do the modeling. We need to continue to
22 understand how these resources work together. If we get
23 more carveouts out there, that weakens the system and we
24 wind up doing non-optimized procurement.

25 You know, we also know the IRP will help

1 California understand the change in the natural gas fleet
2 over time, including the impacts of greenhouse emission and
3 grid flexibility, meaning we know, going forward, IRP is
4 going to help us address retirements of the plants and
5 understand where and if plants are needed in the future.

6 And SB 350 goals and the electricity system
7 optimization are easier to achieve with highly regulated
8 LSEs than numerous locally-controlled entities, and that's
9 kind of a provocative statement. It would be much easier to
10 achieve these goals with a handful of very regulated LSEs.
11 That's not to say we can't do it without more locally-
12 controlled entities or a larger group of entities, and we'll
13 probably be faced with that challenge. It's just it will be
14 more of a challenge and it's going to require greater
15 cooperation and coordination with those entities, both from
16 the regulatory entity looking at those entities, but also
17 from those entities working with the regulatory agencies.

18 And with that, I'm available for questions.

19 CHAIR WEISENMILLER: Yeah. Okay. A few things
20 which actually may be more comments than questions, but I
21 was going to note, the CEC will be adopting the guidelines
22 for the POU IRPs this summer. I'm going to say July is sort
23 of our schedule, is what we're now shooting for.

24 In terms of -- I would also note to connect you
25 and Mark in a way is, as you know, we've done roadmaps

1 historically for demand response, vehicle-to-grid, and
2 storage. And one of the things we're trying to do in this
3 IEPR is actually go back and fine tune those, update those
4 where we need to, to keep everyone on track, moving forward
5 on those.

6 The last observation, if you -- something -- if
7 you'd go back to your RA slide, there's a complication that
8 came out in the workshop we had on reliability issues, which
9 actually sort of reemphasizes your last point and
10 foreshadows the next Friday workshop.

11 As you know, the RA requirement applies to all the
12 LSEs. And at this point, as the IOU loads are dropping they
13 are basically selling RA to the new entrants. It turns out
14 the IOUs are now stopping doing bilaterals, given the flux
15 now. So in terms of, you know, the hope that the bilaterals
16 will keep stuff alive for a longer time, that option is off
17 the table now for anything but the existing long-term
18 contracts, at least that's how I understood their statements
19 at our workshop.

20 MR. RANDOLPH: Yeah. And I didn't hear their
21 statements, so I won't build

22 MR. RANDOLPH: Yeah. And I didn't hear their
23 statement, so I won't build on that too much.

24 But just to kind of go back to the observation at
25 the bottom of this, and this may be more of a short-term,

1 five-year-type horizon, you know? And, you know, the reason
2 why the investor-owned utilities may be willing to sell some
3 resources they have now or not long-term contract is they're
4 long on what they're required to have. And this gets back to
5 you get what you measure, you get what you value. As we
6 further refine what we need from a flexible standpoint, if
7 that's different than what they have in their portfolio
8 right now, or they have just enough of that, they won't be
9 selling that, or they'll be signing contracts for those
10 resources.

11 CHAIR WEISENMILLER: Yeah. Thanks. Thanks again.

12 MR. RANDOLPH: Thank you.

13 MS. RAITT: Thanks, Ed.

14 So next we're moving on to regional coordination,
15 and a presentation from Peter Miller from the Natural
16 Resources Defense Council.

17 (Colloquy between Ms. Raitt and Mr. Miller)

18 MR. MILLER: Good morning, and thank you for the
19 opportunity to speak here today. My name is Peter Miller
20 and I'm representing the Natural Resources Defense Council.

21 We've already had some great presentations, and I'm,
22 unfortunately, going to duplicate some of it because you're
23 going to hear some of the same messages over and over. And
24 I think let's take that as a move towards consensus and
25 agreement on many of these issues.

1 So I wanted to just start with a picture of where
2 we are today. This is today's fragmented western grid.
3 There are 38 different balancing authorities across the
4 western grid. Each one is separately responsible for
5 dispatch and balancing within its borders and it's less than
6 an ideal situation. It's certainly working and it's working
7 well, and I think that goes to some comments Tom said
8 earlier which is that, you know, we have the good fortune of
9 living in a prosperous country and region where electricity
10 is available and relatively inexpensive. But moving forward
11 we have ambitious environmental and economic goals, and we
12 need to improve the situation so that we can reach those
13 goals.

14 So what I wanted to talk today -- what you've
15 asked me to talk about is the advantages of regional
16 integration, of taking that fragmented grid of 38 balancing
17 authorities and combining them into a single balancing
18 authority. There are a number of different benefits that
19 that will provide, and I just wanted to go quickly those
20 different categories of benefits now.

21 The first is operational and management practices.
22 By having essential dispatch and balancing authority, you
23 will get benefits in terms of scheduling, consolidation of
24 control, and sharing of reserves.

25 There are benefits in terms of efficient markets.

1 So by using a market dispatch to provide energy and grid
2 services, you can lower costs and ensure that you're using
3 lowest-cost resources to provide those services.

4 There's important benefits of geographic diversity
5 by having a broad region participate in that market.

6 Those -- the benefits include temporal diversity. So the
7 sun comes up earlier in the east, sets lower in the west,
8 and that smooths out that solar supply curve.

9 There are climatic differences across the region.
10 So when the storm blows through it doesn't cover the whole
11 region, and it will be sunny in one part of the region or
12 windy in one part of the region when it's not in the other.
13 That's both daily, you know, a weather-related difference,
14 but also a seasonal difference. It may be rainier in the
15 northwest one year and dryer in the southwest, and vice
16 versa in the following year. It allows a balancing of those
17 hydro resources.

18 And finally, there's differences just for specific
19 resources in terms of generation profiles. So the wind --
20 the profile of wind generation in California is different
21 than that in Wyoming or in New Mexico, or off the coast of
22 California. And by bringing all those resources into the
23 portfolio and allowing them to balance, you can get
24 important savings.

25 Providing access to those generation resources

1 across the footprint allows customers across the region to
2 benefit from access to a lower -- to lower cost generation,
3 which means you have to go collectively not as far up in
4 terms of the cost stack of the generation resources.

5 So what are the benefits to California customers,
6 utility customers from a regional balancing authority?

7 This was studied at the -- at the behest, the
8 direction of the legislature and SB 350 that asked the ISO
9 to study this question, and when the study was done found
10 that a multi-state regional-electric market could provide
11 significant environmental and economic benefits to
12 California and to the west more generally.

13 The benefits in 2020, as you see from the slide,
14 the benefits in 2020, assuming a relatively small footprint,
15 are relatively modest, about a tenth of a percent of utility
16 bills. With a bigger footprint, they were about five times
17 larger. But those benefits grow dramatically over the
18 coming decade with the effort to reach our 50 percent RPS
19 targets by 2030. And the study found that benefits would
20 range -- would be on the order of \$1 billion to \$1.5 billion
21 per year in 2030, or two to three percent of utility bills,
22 depending on what mix of renewables was procured to meet
23 those -- that 50 percent target.

24 There are, in addition, benefits in terms of
25 emission reductions. The study found that about 10 million

1 metric tons of CO2 emissions would be reduced by the use
2 of -- by reduced curtailment of renewables and access to
3 lower-cost renewables across the region.

4 And there would be a boon to the economy, as well,
5 in terms of job creation. The study estimated that there
6 were 10,000 to 20,000 new jobs that would accrue to the
7 state, primarily from reduced bill expenses. Lower
8 electricity costs allow customers to spend money on job-
9 intensive activities, and that would create jobs and provide
10 a real benefit to the economy.

11 Now one thing important to note is that this study
12 assumed that we were trying to meet a 50 percent RPS for
13 2030. I think everybody is aware that there's a bill
14 pending in the legislature that would move that date forward
15 to 2026. So if that bill passes and is adopted into law,
16 these benefits could accrue much sooner than the end of the
17 next decade.

18 So you've heard earlier about the Energy Imbalance
19 Market, the EIM. But I just wanted to highlight that the
20 Energy Imbalance Market, the EIM, which was launched about
21 two-and-a-half years ago, has now provided benefits that
22 exceed \$173 million, with monthly benefits now coming in at
23 about \$10 million a month. That's significant. The EIM is
24 proving to be very successful and it's growing rapidly.
25 There's now customers in eight states across the west that

1 are benefitting from this program, and a number of utilities
2 scheduled to join in the coming months and years, including
3 Portland Gas & Electric, Idaho Power, Seattle City Lights,
4 and the Salt River Project.

5 The EIM, as you've heard earlier, is a real-time
6 market. It's not the day-ahead market that regional
7 integration would address. It's only five percent of the
8 overall market. But I think it's fair to say that it does
9 provide a model of the potential benefits that we could see
10 from regional integration from the day-ahead market.

11 So I do want to move to something new. I don't
12 know if folks got a chance to see the San Francisco
13 Chronicle article that came out yesterday, reporting on a
14 study that was done by Yale University Environmental
15 Protection Clinic. The clinic recently completed a
16 comprehensive review of policy and -- of the policy and the
17 legal merits of a regional grid.

18 And they asked the question: Would grid
19 integration threaten California's autonomy or authority?
20 And the answer to the headline, to the study, was a
21 resounding, no. The study found that there were no
22 additional legal risks, and, no, that the regional grid
23 would not interfere with the state's rights to regulate
24 utilities or to set energy policies. Those have
25 traditionally been a state prerogative. And the study found

1 that movement towards a regional grid could -- would not in
2 any way threaten those state's rights.

3 Just a quote from the study,

4 "In sum, enhanced western grid integration in
5 general, and the emergence of a regional system operator in
6 particular, would not expose California's clean energy
7 policies to additional legal risks. Shifting to a regional
8 grid operator would enable more efficient, affordable and
9 reliable integration of renewable resources without
10 increasing the legal risk to California's clean energy
11 policies."

12 That study is available online. I can provide
13 access to it. And it's certainly linked through the
14 Chronicle article that was posted yesterday.

15 With that, I want to make myself available for
16 questions. And again, thank you for the opportunity to come
17 speak today.

18 CHAIR WEISENMILLER: Well, certainly. Thanks for
19 being here.

20 I was going to ask you if you could add to our
21 docket that study?

22 MR. MILLER: Absolutely. Be glad to.

23 CHAIR WEISENMILLER: I was going to note,
24 obviously in China, they tend to think bigger than we do. So
25 their idea of a regional market -- or going to their

1 regional market to deal with renewable integration would
2 include Russia and Europe in one local, one regional
3 dispatch operation, which obviously has greater political
4 issues than even we have.

5 MR. MILLER: Yes. That is ambitious, indeed.

6 MR. DOUGHTY: Perhaps we'll move into an
7 interstellar market one of these days.

8 Thank you, Peter. That's a good overview. And
9 something else about the EIM that we celebrate, it's a
10 chance to test drive our relationships with others. Many
11 parties in the west haven't had much engagement with
12 California over the years. And if you look back 17 or 18
13 years ago, engagements that did exist were difficult. So
14 this is a chance for those parties to get to know us,
15 understand who we are, and I think perhaps equally
16 importantly, understand that we have, here in California, no
17 interest in imposing our policy mandates on others. We
18 welcome and honor others with their objectives, both in EIM
19 and, should it occur, in the broader regional market.

20 Thanks.

21 CHAIR WEISENMILLER: Yeah. I probably should
22 footnote what you said. I mean, actually, one of the key
23 initiatives of the first Brown Administration was regional
24 integration. I mean, at one point, certainly the Bonneville
25 administrator was talking about a West Coast vision. That

1 certainly resulted in the TANC project. But certainly,
2 worked very closely with the Governor the first time on
3 trying to enhance renewables. Just given the natural
4 diversity in resources and loads, you know, there's
5 phenomenal opportunities that we've gotten since the
6 interties were built and then expanded in the early '70s.

7 Thank you.

8 MR. MILLER: Thank you.

9 MS. RAITT: Thank you.

10 So next we'll move on to the panel on flexible
11 capacity. So I'd like to invite our panelists to come up to
12 the front tables, and we'll be putting out name tags for
13 you, or name plates.

14 And Kevin Barker from the Energy Commission is the
15 moderator for this panel.

16 We're just taking a moment, for folks on WebEx, to
17 get everything -- get everybody seated.

18 MR. BARKER: So thanks everyone. It looks like
19 we're a little bit ahead of time, which is good. So we
20 might be able to actually get to lunch a little bit earlier
21 than what I was a little bit worried about, after one
22 o'clock. So we're actually on pace here.

23 I wanted to, I guess, kind of start with the
24 rationale for not just this panel, but for the three panels
25 that we have coming forward. The agenda sort of states that

1 the last two panels of the day are looking at solutions for
2 increasing flexibility in the electricity system. That
3 actually should have been right in front of this one, as
4 well. So all three of these panels are to look at
5 solutions. We've broken up the three panels into what we
6 thought were topic areas that were similar.

7 And so the three panels that we have, this one is
8 looking more at the central station power plant type of
9 solutions, both conventional generation, renewable
10 generation, and then also looking at the hydro system. The
11 second panel of the day will be looking more at flexibility
12 of demand, that being mostly demand response and energy
13 storage, but also looking at how we look at distributed
14 resources in general. And then the last panel of the day
15 will look at what I think folks have highlighted earlier in
16 the day of what do we do with -- if we do have excess
17 electricity, rather than curtailing what could be carbon-
18 free resources, can we actually take advantage of the cheap
19 and GHG-free resources on electricity -- with excess
20 electricity?

21 So I think how -- so we've kind of coordinated.
22 And how, this panel, we plan to outline the panel is that
23 we'll have opening remarks, around seven minutes each from
24 the panelists. The kind of goal is for them to be able to
25 highlight, you know, what they bring to this flexible

1 capacity topic area. I think each panelist will have
2 something very unique to discuss. And then we will have
3 some high level kind of questions that follow.

4 What I've seen work in the past, and I'm just
5 thinking about this now, is rather than direct any of these
6 specific questions to the panelists, I'll kind of throw it
7 out to the full panel. And if you'd like to discuss, just
8 take your -- if you'd like to comment, just take your
9 nameplate and put it there, hopefully it stands, and I'll be
10 able to call on you with that. And then we'll leave some
11 time at the end for our dais to ask questions.

12 So with that, please, as we go down, feel free to
13 introduce yourself. We're going to start with Bonneville,
14 with Kieran Connolly from Bonneville. And just yesterday, I
15 heard this phrase of the Pacific Northwest Battery, and I
16 didn't exactly know what that meant. But then looking at
17 the huge potential of the hydro system that we have in the
18 northwest, how can that be better utilized, both for your
19 needs, but then also our needs down here.

20 So please feel free to take it away, Kieran.

21 MR. CONNOLLY: Thanks, Kevin, and thank you for
22 having me here today. My name is Kieran Connolly. I'm the
23 Vice President for Generation Asset Management at Bonneville
24 Power. And my presentation today, I'll spend a little bit
25 of time talking about our system and kind of the drivers

1 behind our system, because I think that's important for how
2 we can participate in helping California meet its goals. We
3 have a long history of working together. And our
4 coordination, you know, goes on today. We spent a lot of
5 time with our friends at the California ISO, and we hope to
6 continue that relationship.

7 We'll flip to the next slide. And there's a
8 couple of things you can fly in there if you clip a couple
9 more times.

10 So this map shows the Columbia River Power System.

11 I think one more.

12 And this is really a partnership. The Corps of
13 Engineers and the Bureau of Reclamation actually operate the
14 facilities on the Snake and Columbia River that are
15 federally operated. Bonneville then coordinates the water
16 flow for both power and non-power uses, with the exception
17 of flood control. Our friends at the Corps of Engineers
18 take care of that. And then we also then market the
19 resulting power output, either to meet our preference
20 customer loads or more broadly in the west. And the
21 resources themselves at the federal hydro projects, we're
22 very proud of them. I call them Ferraris. Our hydro plants
23 can move very rapidly. We have a fair amount of capability
24 in our reservoir storage to both pick up and then back off
25 our fuel supply.

1 In fact, we used to think of flexibility and
2 capacity almost as a waste resource. And when I started my
3 career at Bonneville 25 years ago, we focused on energy
4 planning for low water years. That was our focus. That has
5 changed over time as we have had more non-power restrictions
6 on the system. But the system is still very capable of
7 providing flexibility. What it requires us to do is plan,
8 and that's the thing I'm going to talk about and how that
9 interacts with the way we approach operating the system.

10 In addition to the federal system, there are non-
11 federal projects in the United States. And our Canadian
12 friends to north also operate substantial facilities. I'm
13 going to focus on the federal system, because that's what I
14 know something about. But a lot of these same comments, I
15 believe, apply to their resources, as well.

16 I'm going to come back to the -- well, one thing
17 I'll say here, when you take a look at this map one of the
18 key considerations with our hydro system is that these
19 projects are interlinked. So when I release water at a
20 given project, whether that's for power generation or for
21 spill, I'm not only looking at what that can do to meet load
22 and to position water with regard to our constraints now,
23 but we're thinking about how's that going to impact our
24 ability to meet load and meet constraints an hour from now,
25 tomorrow, next week, and later on this month?

1 So this the challenge that we constantly face
2 because we have reservoir targets to hit, flow releases to
3 hit on a continuous basis. Some projects have rate of
4 change constraints where have to be careful. If I put an
5 inflection point in that rate of change over a 24-hour
6 period, that then limits my operator for the -- until that
7 rolls off the 24-hour rate of change.

8 So these are the kinds of things that we're
9 looking at when we're trying to optimize water over time. We
10 look at this both from an economic standpoint, and then when
11 we get pushed far enough it's a question of can we meet our
12 non-power constraints? We don't like to violate those non-
13 power constraints. I get in big trouble when that happens.

14 If we'll flip to the next slide, I'll transition
15 to transmission for a moment.

16 So the interties between the northwest and
17 California, of course, have been a wonderful asset for the
18 west over the years. And there's different natures for how
19 we operate the different parts of the facility, starting
20 with the DC Intertie that comes into Los Angeles. Given the
21 equipment there and the need to do the transformation to DC
22 power, that is limited to hourly capability at this time.
23 So we do time steps for commercial transactions of hourly
24 schedules across the DC.

25 Now we are looking and discussing with our friends

1 in L.A. automation to be able to move that to a more
2 frequent basis, but that's something that would be in the
3 works for the future.

4 On the COI we have a full 4,800 megawatts of
5 capability when it's fully available, and that's scheduled
6 down to a 15-minute basis for the full amount. And then on
7 that same COI interface, we have 400 megawatts of dynamic
8 capability. And this gets to what would be appropriate for
9 dispatch in a five-minute increment. This is really going
10 to the stability of that COI interface over time.
11 Particularly, we can get challenged when it's highly loaded
12 with regard to stability issues there. So that's something
13 that our transmission folks watch very closely.

14 Moving to the next slide, this is back to the
15 hydro system. And this is a theoretical snapshot of how we
16 would look at the system as a whole for one day. And if
17 you'll start in the upper left-hand side, we're taking our
18 capability, were de-rating it for outages. We're holding
19 out our required reserves for maintaining reliability on our
20 system from the top. And then at the bottom, we're building
21 up our obligations, so Bonneville's native load customers.
22 We have a significant obligation to return energy to Canada
23 under the Canadian entitlement for the treaty with Canada.
24 We're making long-term transactions, either with our
25 preference customers where they have rights to take power

1 based on the capability of the system. And there's also
2 longer-term market transactions.

3 Basically, Bonneville is typically surplus at any
4 given time. And what we're trying to do is we're building
5 our loads to match that water flow that we need to achieve.

6 And as we commit those resources, again, thinking
7 about that map and how the water is going to flow and impact
8 what I can do at subsequent snapshots like this, we're
9 locking that in to try to get an optimal output, consistent
10 with our non-power obligations. So as I move closer to a
11 real-time situation, on the day-ahead I'm trying to lock in
12 some capacity commitments to really achieve that operation.
13 So if you move to the bottom chart there you'll see
14 Bonneville is basically balancing out that load versus water
15 situation.

16 And then if we have flexibility products, we kind
17 of look at them as two different things. One is sort of
18 known flexibility, where you're looking to make use of the
19 ramping capability and the frequency response, et cetera, of
20 the system, but you have a fairly known energy content
21 associated with that. So it doesn't really impact that
22 water flow that I'm trying to optimize over time.

23 And then there are other products with a really
24 unknown energy content to them. And this is situations
25 where, I mean, the most extreme would be we could have 100

1 percent energy output of that product, or we could have a
2 flip-side actual return of energy, at that same time a
3 negative energy content from the purposes of moving water.
4 So in that case, I have to deal with a whole spectrum of
5 where am I going to store or make up for a lack of water
6 movement across my system.

7 So the first place that impacts Bonneville is
8 economically we're going to have to counteract that
9 uncertainty in our operations. So we're going to end up
10 generating at a time where either it's economically
11 disadvantageous for us, or we're having to spill in order to
12 compensate for getting our water back where we want it. So
13 as we move into time the more uncertainty that we're facing
14 in the products or the more short-term needs we face, it
15 becomes more difficult for us to meet that need.

16 Conversely, the more the obligations are known to
17 us the more we can actually leverage our system and provide
18 more services, or, on the flip side, if folks -- if there's
19 greater compensation, of course, you're willing to suffer
20 some of those slings and arrows, not the ones where you're
21 violating constraints but ones where maybe you otherwise
22 would be de-optimizing from serving your customers at the
23 least cost.

24 And now we'll flip one more.

25 This kind of is then the intersection for us with

1 California's flexibility needs. Today, and generally, the
2 compensation and the drivers, given our uncertain hydro
3 operations that we're trying to lock in, push us to provide
4 sort of bulk power; right? Generally there's a price
5 differential between northwest markets and California
6 markets that say push energy into California, and so that's
7 what we do, we push energy into California, somewhat on the
8 peak hours because those tend to be a higher price, but also
9 on other hours because there's carbon value embedded in that
10 price. There is generally a price spread between the
11 northwest and California, and it allows us to utilize that
12 transmission that we've got between the northwest and
13 California.

14 And so from our perspective, if we're going to
15 hold resources open and put less energy content, both down
16 the intertie and on our turbines, right, what we'd like to
17 do is look for ways of designing products that give us some
18 degree of knowledge about how much energy content can we
19 expect? And that's something we've done in the northwest,
20 we've sort of separated -- when we look at our changes in
21 variable resources, we've separated sort of the more known,
22 the predictable part of the error, from the unknown, have to
23 wait until the last five minutes to manage that error,
24 because that works better for our system.

25 We also think on the most basic standpoint from an

1 adequacy product, there's just the question of eligibility;
2 right? Resources that are outside the system, if they're
3 not eligible, of course, they can't participate and can't
4 help make supply and bring down prices.

5 But then in these design questions, making sure
6 that if we can show that we're helping with the carbon
7 problem even when we're not pushing megawatts to California,
8 if there's a way to account for that, that would be helpful,
9 so we don't have these differentials between our sources of
10 opportunity in energy markets versus our sources in
11 flexibility markets.

12 And I think I'll stop there because I'm probably
13 pushing my seven minutes.

14 MR. BARKER: Great. Thanks a lot, Kieran.

15 So let's -- well, one thing I would just note,
16 sort of a theme as you -- as we walk down the panel we'll
17 see a lot of the generators that both have, you know, the
18 kind of conventional generators, but also have renewables
19 and they're looking at ways of exploring flexibility in both
20 fleets. And so I think that's really something that's
21 interesting. You know, at least for the renewable power
22 plants five years ago or seven years ago really weren't
23 looking at the flexibility, they were just looking to run
24 100 percent, if they could. And so I think that's going to
25 be an interesting conversation.

1 So let's go to Amol Mody with GE, and please take
2 it away.

3 MR. MODY: Yeah. Thank you, and thank you to the
4 CEC for having us here. I'm Amol Mody. I'm with GE Gas
5 Power Systems. And although my background is in
6 conventional generation, I'll add some color and hope to
7 provide some insight on technology as far as renewable
8 generation goes and the advancements GE has made over time.

9 GE, again, is a digital-industrial company. And
10 if you'll flip to the next slide, we play in the entire
11 energy ecosystem, everywhere from the extraction of energy
12 and raw materials to the delivery of energy and helping the
13 consumer consume.

14 For this setting, I'd like to focus on a couple of
15 aspects that GE is focusing on and a couple of trends that
16 we see over the next few years, and what we're doing to
17 address those trends.

18 Decarbonization and digitization, if you flip to
19 the next slide, again, this was mentioned earlier,
20 decarbonization isn't a California-only problem, it's a
21 global problem. And it's a global opportunity for us to go
22 address. And we're constantly investing in various
23 technologies. We're helping wind produce more energy.
24 We're helping solar panels get more efficient. We're
25 helping hydro be more effective. And we're also focused on

1 making conventional generation assets, conventional
2 resources more flexible. We're helping reduce pMin. We're
3 helping ramp rates. We're just helping our assets and our
4 customers' assets become more efficient.

5 Our ultimate goal here is how do we help our
6 customers be better participants in the grid and continue to
7 provide services that are necessary for decarbonizing the
8 grid.

9 The other aspect I want to touch on briefly here
10 is the digitization of energy. If you flip to the next
11 slide, as a digital-industrial company, we're really focused
12 on big data analytics and improving customer and stakeholder
13 outcomes. However, there are some challenges, at least at
14 this stage, in terms of data analytics. Data access is very
15 limited. Only less than two percent of data is captured
16 today, and a lot of it's done without automation. A lot of
17 the old assets that are installed and existing don't have
18 the ability to provide data to GE or to other analytic
19 companies to really help optimize those assets. So that's
20 really a lost opportunity that I think there's a place to
21 maybe extract some value from.

22 There are a lot of huge potential benefits here.
23 Major reliability improvements are at stake. We can also
24 increase efficiency and reduce emissions of existing assets.

25 One of the examples of using data to work on a

1 renewable asset is our digital wind farm, the ability to
2 squeeze more energy output out of a wind turbine, making
3 sure we have better forecasting abilities, and taking
4 advantage of ramps in wind quicker than we have been able to
5 in the past.

6 So I'll summarize pretty quickly here. Our
7 perspective is that technology and geographic diversity are
8 key when it comes to addressing some of the state's needs.
9 And we would urge regulators to consider the benefits of
10 various technologies and keep the technology options open.
11 We're doing some really exciting things. Very recently,
12 we've combined energy storage with gas-fired generation to
13 create a very flexible resource. I mentioned the digital
14 wind farm. And we're working on some very similar things
15 with the hydro-installed base, as well, to help extract more
16 value, given the assets that are in the field of play today.

17 Thank you.

18 MR. BARKER: Thanks, Amol.

19 Let's go now to Matthew Barmack at Calpine.

20 And another tweak and interesting thing that
21 Matthew will talk about is what kind of things can you do to
22 help build flexibility into the CHP resources?

23 Take it away.

24 MR. BARMACK: Thanks for having me. I'm Matt
25 Barmack, Director of Market and Regulatory Analysis at

1 Calpine.

2 We have a very diverse portfolio of resources in
3 the state. There's a lot of flexibility in the resources.
4 We see a lot of additional potential flexibility. We sort
5 of struggled with the appropriate business model to support
6 that flexibility. And, you know, I'll talk about some of
7 those challenges as I just walk through kind of the asset
8 classes.

9 So if you could go to the next slide please?

10 You know, probably our fastest and most flexible
11 assets are CTs. We have 11 LM6000s. These are relatively
12 modern, aero derivative combustion turbines. I'm not sure
13 whether they're digital or analog. We bought them from GE
14 quite a while ago. But, you know, these are our most
15 flexible assets. We have four of these that are rolling off
16 of contract at the end of this year. And we haven't been
17 able to figure out how to make the economics of keeping them
18 operating, pencil out. So we approached the ISO and told
19 them we were no longer going to operate four of them after
20 this year. The CAISO indicated a willingness to designate
21 two of them for RMR contracts, basically to address local
22 reliability issues, not necessarily flexibility issues.
23 Right now we're not planning to operate the other two beyond
24 this year.

25 I just wanted to give you a sense for how these

1 operate. This graph shows how these four plants operated in
2 2014 and 2015, so the data are a little bit stale. The
3 graph shows the number of days over this two-year period,
4 sort of by hour of the day which the plants operated. And
5 you can see sort of a very pronounced pattern. They don't
6 operate for very many hours, but they operate on a lot of
7 days, sort of in the early evening hours, just as the sun is
8 going down. So I have a colleague who refers to these as
9 the sunset peakers.

10 Why don't we go to the next slide?

11 We also have geothermal. We have the Geysers,
12 which is a 720 megawatt geothermal plant. I think it's not
13 fully appreciated how flexible the Geysers already is. So we
14 routinely offer it economically in the CAISO markets. This
15 graph shows a couple days on which it was dispatched down,
16 approximately 300 megawatts on, you know, several days in a
17 row or in close succession. Pretty routinely, we think we
18 could dispatch it down about 400 megawatts for up to four
19 hours. And we're very grateful for a CEC grant to explore
20 making it even more flexible.

21 Next slide please.

22 So the bulk of our portfolio is combined cycle.
23 We have about 4,500 megawatts operating in California right
24 now. You know, we've thought about a lot of ways to make
25 these more flexible. And this somewhat busy and illegible

1 slide illustrates the types of improvements that we think
2 are possible. So the left slide is -- the left part of the
3 slide is really the improvements we think we can realize.
4 And the right half is, you know, sort of what the upgrades
5 involve from an engineering perspective.

6 So, you know, I'll try to walk through some of
7 these very quickly. But, you know, basically we think we
8 can realize shorter starts. A lot of the limitations on the
9 flexibility of combined cycles really relate to the steam
10 part of the plants. So, you know, combined cycles involve
11 combustion turbines that are, you know, very similar to
12 standalone peakers. Then we take the waste heat, use it to
13 make steam, use that steam to make electricity. The steam
14 parts of the plant don't like big changes in temperature.

15 And so, you know, the way we can make combined
16 cycles more flexible is sort of moderating some of those
17 changes in temperature, or also somewhat decoupling the
18 operation of the combustion turbines and the steam part of
19 the plant. So, you know, potentially we could operate the
20 combustion turbines completely independently of the steam
21 part of the plant, in which case the starts could be very
22 rapid.

23 You know, we've also looked at upgrades that could
24 result in lower minimum operating levels. And then just the
25 last two rows of the left slide of this slide show, you

1 know, what all these improvements would do with respect to
2 how a typical two-by-one combined cycle might count for
3 flexible resource adequacy under the current rules.

4 And then the right side is, again, you know, some
5 of the engineering. You know, so there are turbine upgrades
6 that enable lower turndowns and, you know, faster ramp
7 rates. I'm sure Amol would like to sell us some of those.
8 And then, you know, on the steam side there are a bunch of
9 things that we could do, ranging from the mundane to the
10 more involved.

11 So one of the simplest things we could do is put
12 thermal blankets on parts of the steam side of the plant and
13 just keep it warm when it's not operating. And so that
14 makes it easier to start when we bring it back up.

15 You know, then somewhat more involved would be
16 steam bypass which would involve, actually, you know, when
17 we start the plant, actually wasting some of the steam, not
18 subjecting the steam side of the plant to, you know, that
19 huge thermal stress, letting it warm up slowly but sort of,
20 you know, enabling us to operate the combustion turbines at
21 close to full capacity when that happens.

22 You know, purge credit, every time we start a
23 combined cycle, we have to blow air through the heat
24 recovery steam generator to make sure there's not still gas
25 in there that can combust. If we did that when the plant

1 shuts down and then sealed it off instead of when the plant
2 starts, we could start a plant much more rapidly.

3 And then, you know, the last thing I'll mention is
4 auxiliary boilers, either gas or electric, to keep parts of
5 the plant warm. And if they were electric, that could
6 actually be a flexible load that could soak up some of that
7 overgeneration in the middle of the day.

8 So we've been looking at these kinds of upgrades
9 for a long time. We haven't been able to find an interested
10 or willing buyer. I will note that I believe Southern
11 California Edison and Pacific Gas & Electric did some of
12 these types of upgrades to the combined cycles that they
13 own. Obviously, they have the benefit of regulated rate
14 recovery, which we don't.

15 So finally, before I move off this slide, I wanted
16 to mention one more thing, and this is sort of a natural
17 transition to the last slide. I think there's a common
18 perception that combined cycles are inflexible and
19 contributing to the overgen conditions in the middle of the
20 day.

21 And I just want to share with you, you know,
22 anecdotally, I've been following somewhat closely the way
23 our plants have been operating recently, and they're not
24 operating in the middle of the day. In fact, for the most
25 part, they're completely off. Generally what's happening is

1 we're starting in the late afternoon to meet the evening
2 ramp, you know, the neck of the duck. And then the plants
3 actually stay on overnight to meet the morning ramp, and
4 then they shut off in the middle of the day. So it's sort
5 of like the way they used to run. You know, they would sort
6 of cycle daily, and they would start in the morning and run
7 through the afternoon and shut down at night. Now the
8 middle of the day is the new off peak. So we're not running
9 in the middle of the day and we're shutting off overnight.

10 With the exception of -- next slide please.

11 One of our combined cycles, so Los Medanos is a
12 combined cycle, but it's also CHP plant. We serve fairly
13 large steam and electrical loads associated with DOW
14 Chemical and POSCO Steel in the Delta. And the electrical
15 load is about 60 megawatts. To serve that load with our own
16 generation, we have to run the plant at least 190 megawatts.

17 And if we don't do that, basically we're on the hook for
18 the PG&E Standby Tariff, which, you know, don't quote me on
19 this, it's in the range of, you know, \$.10 a kilowatt hour,
20 so \$100 a megawatt hour. So basically that incents us to
21 run through the day, even though it's uneconomic from sort
22 of a wholesale market perspective.

23 And this seems like some very low-hanging fruit
24 with respect to flexibility. And we've had some really
25 constructive discussions with PG&E about potential solutions

1 to this problem.

2 So, yeah, I mean, that's the range of flexibility
3 that we see in our portfolio right now, and we're just
4 looking for the right business models to bring it forward.

5 So thank you.

6 MR. BARKER: Thanks a lot, Matthew. Thanks a lot,
7 Matthew.

8 Now turning to NRG, Brian Theaker, please go
9 ahead.

10 MR. THEAKER: Yeah. Thank you, Kevin.

11 My name is Brian Theaker. I'm Director of
12 Regulatory Affairs for NRG.

13 Kevin, thank you for the invitation.

14 Commissioners Weisenmiller, Randolph and Douglas,
15 thank you for this opportunity. Tom, as well.

16 So NRG operates about 7,100 megawatts of
17 conventional generation in California. We also operate
18 about a 1,200 megawatt utility scale solar portfolio. And
19 like many of the folks in this room, we're killing ourselves
20 to try to figure out how to get into the emerging storage
21 market. So those are the things that we're currently
22 involved in.

23 I don't have a technological pony to ride for you
24 today. Most of my message will be about the process. And
25 I'll start by agreeing with Tom that this is a time of

1 unprecedented opportunity. You know, what a great problem
2 to have, is all of this surplus carbon-free energy in
3 California. So we have a window to -- that's open now to
4 try to figure out how to -- how best to use that, and how to
5 address the operational challenges.

6 Part of my message today will be to say during
7 this open window, we need to do it in a thoughtful way.
8 Because to borrow a concept from Mr. Randolph, you know, to
9 look at this in an integrated fashion and to how we think
10 about providing a glide path, a transition for some of the
11 resources that we're going to need over the next term in
12 order to have a smooth and reliable transition towards a
13 more carbon-free grid. So that will be the bulk of my
14 comments today.

15 But I also wanted to give you some really
16 interesting data from the ISO. I am an unabashed data
17 junkie for CAISO data. And, Tom, Mark, you published some
18 really interesting stuff, and so I could not waste the
19 opportunity to show you some of that stuff.

20 The upper left-hand corner is actual duck curves.
21 This is not projected ducks, these are actual ducks from the
22 minimum net load day, 2011 to 2017.

23 And, Tom, I can't help but think that if the ISO
24 had trademarked the duck curve and charged royalties for
25 every time it appeared in public, that maybe you could make

1 a significant dent in the transmission revenue requirement.

2 MR. DOUGHTY: Brian told me today, there's
3 actually a Wikipedia page on the duck curve, so --

4 MR. THEAKER: Yeah, there is, with a real duck, so
5 I encourage you to go look at that.

6 Mark talked about April 23rd. That's the low
7 trace you see in that graph. It's kind of a remarkable date
8 to hit a net load just above 9,000 megawatts. And Clyde
9 thinks we might be pushing that this weekend, so we'll see.

10 But it also shows you that the time of the net
11 load peak, or the minimum net load, I should say, has
12 changed from three o'clock in the morning to three o'clock
13 in the afternoon. So this is not your father's grid. This
14 is the emerging grid.

15 The graph below that is a duration curve of the
16 three-hour net load change. And so what that shows is that,
17 especially in '15 and '16, we've really had an accelerated
18 transition towards higher and higher three-hour net load
19 changes. But what I don't show in this is we've seen the
20 same phenomena with a one-hour net load change. So speed
21 has become an increasingly important concept in ramping for
22 the ISO. We've seen a 62 percent increase over the last
23 five or six years in the size of the net load ramp, the
24 three-hour net load ramp. We've seen a similar change in
25 the one-hour net load ramp, not quite as big, it's about 50

1 percent. But clearly the need for and the nature of
2 flexibility is evolving on the grid.

3 The upper right-hand graph is the ISO's
4 interconnection queue. It shows you that the queue is both
5 a source of increased challenge, but also a source of
6 increased opportunity to deploy some of these technologies
7 to beat the flexibility needs.

8 And then finally, the graph in the lower right-
9 hand corner is a graph of thermal generation, that's the red
10 column, as well as renewable generation, the green column,
11 and solar generation, the orange column. And you can see
12 the dramatic falloff in total thermal megawatt hours over
13 the last few years. We're down about 50 percent year to
14 date in 2017 based on where we were in 2014, about 20
15 percent down from 2016. That trend is going to continue.
16 But, obviously, as we have fewer thermal megawatt hours,
17 we're going to see increasing challenges with the economic
18 viability of that fleet.

19 Okay, so on to my three points.

20 First, the interim flexibility requirements that
21 the PUC enacted a few years ago has been a great proof of
22 concept. It's demonstrated that we can enforce forward
23 procurement of flexible capacity. It's worked very well.
24 Unfortunately, it's not really effected procurement. It
25 hasn't shown much forward value for flexibility. And we've

1 seen that the three -- that this program, which is based on
2 the three-hour net load curve, has largely run its course
3 because of the increasing importance of speed in the one-
4 hour net load ramp. So it's time to take a look at that.
5 And the ISO has embarked on a fundamental reexamination of
6 flexibility, and that's -- the timing couldn't be better.

7 And that gets to my point, too, which is that is a
8 very important process and we should move forward with it at
9 all deliberate speed. But I would remind us all that a
10 couple of weeks ago we were in this very room, talking about
11 retirement of power plants, and how do we make sure that we
12 do that in an orderly way? So I think that it's necessary
13 that we, as we look at the flexibility needs of the system,
14 we try to come up with as quickly as possible the right set
15 of durable products, so that we can then create the multi-
16 year-forward contracting structure that's going to be
17 necessary to ensure a smooth glide path for the thermal
18 fleet as we move towards an increasingly carbon-free grid.
19 It's important work. We shouldn't shortcut it.

20 And we heard from the utilities on April 24th,
21 that uncertainty around product definition is not going to
22 encourage them to contract over the longer term. So it's
23 important that we take this opportunity to reexamine the
24 need for, and the flexibility products, but to get it right
25 and not rush that.

1 And so finally, the last thing I want to say is
2 Clyde's presentation on the First Solar demonstration
3 project is fascinating, but it's not unexpected. Inverter-
4 based machines can react very, very quickly. And when you
5 have the right incorporated control system, they can
6 absolutely provide the grid services that we need.

7 The challenge is, for getting increased
8 flexibility from renewables, are not technical, they're
9 commercial and contractual, and creating the market products
10 that would sustain these technologies, providing these
11 services in a way that makes commercial sense.

12 So that work has started. You know, we've already
13 had some discussions with our counter parties about
14 restructuring contracts to take advantage of some of that,
15 and that work needs to continue because the hurdle is
16 contractual and commercial and not technological.

17 One final caution on that, these variable energy
18 resources, intermittent resources, are really good at a lot
19 of things. But we should not recreate the mistake of trying
20 to stick them into every -- you know, these round resources
21 into every square shaped reliability hole. So they are very
22 good at some things. They're not very good at some other
23 things.

24 For example, with the groundbreaking work that the
25 PUC and Calpine and E3 have done around capacity value of

1 renewables with effective load carrying capability, you
2 know, we've learned that we probably overstated the capacity
3 value with these resources for a while.

4 So these resources are absolutely an essential
5 piece of the puzzle going forward. But let's not try to
6 force them to do things that they were not designed to do.

7 Thank you, and I look forward to the panel
8 discussion.

9 MR. BARKER: Thanks a lot, Brian. Thanks for
10 sharing that slide of the actual duck. It looks like a very
11 health and fat duck, which is maybe a scary thing, but --

12 MR. THEAKER: No foie gras comments, Kevin, I
13 promise.

14 MR. BARKER: So for our next two panelists, we'll
15 be focusing on the renewable piece of flexibility. And
16 we've already heard from Clyde about solar, and Matthew on
17 geothermal. And so we're going to hear more on geothermal
18 and the pilot work that Ormat have done. And then we'll
19 hear about wind, too. But I guess I would just note that
20 biomass is still out there, and you're not off the hook for
21 bringing flexibility to the table, as well.

22 So with that said, please, Josh, go ahead.

23 MR. NORDQUIST: Thank you. Thank you. And, of
24 course, thanks for having us here today.

25 As stated, Josh Nordquist with Ormat Technologies.

1 We are a renewable energy company, just located just over
2 the border in Nevada. But we currently own and operate just
3 over 500 megawatts of renewables here in the U.S.; 200 of
4 those megawatts are inside the state of California, and
5 another 40 megawatts are in Nevada, providing to California
6 today. So we -- and those numbers are growing, I think, is
7 the other part, too, that we see some unique changes in the
8 product coming forward that we'll talk a bit about today.

9 My main message today is, of course, as these
10 slides are actually titled, is to promote geothermal as a
11 flexible resource. And for a little bit of background and
12 introduction to the company, we're, of course, a renewable
13 energy developer, which we're well known as, but we're also
14 a technology developer. We are a company who is the only
15 vertically integrated geothermal developer out there today,
16 which means, amongst other things, that we also design,
17 manufacture and operate the power plants that we run. And
18 because of that, we have been developing these power plants
19 to new forms today that weren't available in the past, and
20 now find them as a potential flexible provider, or flexible
21 service provider.

22 So maybe if you could skip forward a slide or two?
23 Yeah, perfect. I think there's a legal slide in there that
24 has no meaningful value whatsoever.

25 So to start out, too, I think the overarching

1 statement is that we see both our geothermal fleet and the
2 new geothermal fleet that we're building as having the
3 ability to provide 100 percent flexible resources. Now, of
4 course, many of them are contracted today, but they have the
5 technical ability, as was stated before and stand behind
6 that, that the solution is not technical, the solution is
7 commercial and contractual.

8 The geothermal that we see today can provide --
9 I've listed kind of these services today as maybe a starting
10 point for discussion, but they can qualify as flexible
11 capacity. They have the ability to provide 15 to 30 percent
12 of their nameplate per minute in ramping, both ramping up
13 and ramping down. And because, of course, these systems are
14 built on spinning generators, they're key supporters of
15 voltage and frequency regulation, as long -- as well as
16 spinning reserves.

17 We have -- we've, of course, been watching it.
18 And to touch upon the contractual and commercial needs here,
19 you know, geothermal is a unique source. And though it's
20 probably been stated 100 or more times in this room, it's
21 always worth at least putting out there, we're very well
22 known as the base-load renewable. And we've got wonderful
23 companies like Calpine, who have been in the state for over
24 65 years providing that. And today we really -- we're going
25 to shift that focus because it's not just base load, it's

1 base load and flexible.

2 And I think to -- at least for one (indiscernible)
3 for Calpine, the work that they've been doing, which has
4 been trying to basically find ways to optimize, you know,
5 what can be decades' old technology, in a sense, to do
6 things that are needed today is phenomenal. We also need to
7 pay attention to the new technology today which is being
8 built to provide those services, as well. And I think
9 that's hopefully the message we can drive a bit today and
10 create some questions to answer. So I say that geothermal
11 can do these things, and we lead by example.

12 And if we can move on to the next slide.

13 My main example is that we have a power plant in
14 Hawaii, which is the only geothermal power plant in Hawaii,
15 on the big island. A wonderful place. Lots of lava flows,
16 which is a problem we don't have here in this state. But
17 pretty uniquely, this power plant has been there since the
18 early 1990s, so it's -- and has been kind of repowered and
19 reconfigured over the years as a mix of kind of old
20 technology and new technology. It's the major generator on
21 this island, so it provides the lead generation where
22 everyone interconnects to. And it currently runs on a
23 partial full flexibility or dispatchable mode. It runs on
24 automatic generator, controlled by HELCO, the local utility,
25 and it can be dispatched anywhere between 22 to 38 megawatts

1 upon request.

2 And I only -- I touch base on that partial
3 dispatchability because that's the mixture between kind of
4 an old generation system and a new generation system. And
5 some of that old generation system just simple is stretched
6 to its limit and cannot be as flexible as new technology
7 today.

8 The ramp rates are listed here, and they're listed
9 here because these are strictly -- these are straight from
10 the PPA requirements that this particular system has to --
11 is to be required two megawatts per minute which is, you
12 know, a little lower than, for example, what I just stated
13 as 15 to 30 percent of the nameplate, again, reference to
14 the fact that this kind of an old and new mixed power plant,
15 and it is always providing 3 megawatts of spinning reserve.

16 So this is not -- you know, as I kind of
17 mentioned, we don't see this as pilot project. This is a
18 project that's under contract for these services. It's been
19 under contract now for about, I'm going to say six to eight
20 years. And it experiences no issues in providing these
21 services.

22 So the next slide is a bit of explanation of how
23 things work. And I won't dive too into the detail. But if
24 it's necessary, I'm happy to answer any questions, of
25 course. Now the reason that this works is because this type

1 of technology, which has been labeled a number of things,
2 but for some of them, binary geothermal or organic rank
3 (phonetic) and cycle technology, has essentially two closed
4 loops. And one is the geothermal closed loop, important
5 because the geothermal systems today, they must operate all
6 the time. They must flow consistently, production and
7 injection, constant and uninterrupted to operate at their
8 best, whether we're generating zero megawatts or full
9 megawatts.

10 And the power-cycle system, or the binary system,
11 is unique in that it's also a closed-loop system. It can be
12 similar to steam systems and how they work today, except
13 we're not using steam, we're not using water, we're using
14 hydrocarbons. And this is useful because in using
15 hydrocarbons we don't experience the same difficulties in
16 partial generation as steam systems do. We don't experience
17 problems when we get droplets on blades, for example, or we
18 have partial pressure flow into a turbine. These systems are
19 designed simply to operate in these scenarios and are
20 unaffected. So they can run, again, at a very low
21 generation mode to full generation and be able to ramp from
22 0 to 100 percent very quickly.

23 They can also do this ramping because the
24 geothermal system, as I mentioned, is always running. The
25 heat or the fuel is always right there and waiting. And

1 everything is hot and ready, as we like to say, because this
2 fuel is running all the time.

3 Also noting, because it was brought up earlier
4 today and I think it's always worth stating or restating,
5 you know, geothermal is unique, too, because we're -- our
6 fuel, our heat that we convert to energy is from the core of
7 the earth. This is something that is unaffected by weather
8 patterns, is unaffected by clouds and wind. And it offers,
9 again, a kind of a unique source in renewables that is there
10 all the time and waiting. And we don't -- there's no real
11 planning for it. It's simply always there.

12 So to kind of balance things out and to reference
13 some of the work that's been out there today, you know, the
14 RETI 2.0 work and studies that have recently come out over
15 the last couple of months have highlighted some of the
16 resources that are out there today. Right about, I want to
17 say, around 2,500 megawatts of geothermal capacity is stated
18 available inside the state as determined known resources
19 that are ready to be developed and built today, and then an
20 additional up to 2,000 megawatts outside the state. So
21 together, only being 4,500 megawatts and knowing that that's
22 a relatively low number than the needs are out there today,
23 but it does indicate that geothermal can play a role in this
24 discussion forward as either a base-load resource or a
25 flexible resource, and can play a considerable benefit in

1 determining the flexible needs coming up here.

2 I think with that, that covers all my talking
3 points I've written down here, and I'll look forward to any
4 questions.

5 MR. BARKER: Thanks a lot, Josh. I think the case
6 study you have was interesting. And, you know, something
7 that Clyde pointed out in their study with solar was the
8 ability to not only just have downward ramp, but upward
9 ramp. And so I think that's going to be something that
10 we'll hear on our -- with our next panelist, as well.

11 And so just to introduce ERCOT and Resmi, the
12 Chair was in Austin a few months ago and met with your CEO.
13 And I don't know if this is the first time that you learned
14 about the rules that you have in place to allow for both
15 downward and upward ramp. But, you know, looking at the
16 size of your wind capacity at say 15 gigawatts, and add in
17 another 7 gigawatts, that's a lot of wind capacity in a sort
18 of less interconnected system. And to put that into
19 perspective, California sits with about 7 gigawatts. So
20 quickly, we'll be about a third of your capacity. And so
21 learning from you guys that are on the forefront is really
22 going to be interesting. So, please.

23 Oh, and I guess I would note, so you now have the
24 heads-up that there is interest from our Chair in the -- in
25 their study. So if you -- I know we weren't planning on

1 that, but if you have a few remarks now you can add, or you
2 know that question will be coming soon.

3 So go ahead.

4 MS. SURENDRAN: Thank you, Commissioners, for
5 inviting us to the panel. So as Kevin said, I'm Resmi
6 Surendran. I am the Senior Manager of Market Operations,
7 Analysis and Design at ERCOT. And today, I'll go over in
8 general what renewable integration we have seen, what
9 problems we have seen, and how we tried to address those
10 problems.

11 So if you go to the next slide?

12 So ERCOT, as most of you would know that, is quite
13 different from other areas, not just in that it's not on the
14 FERC, but it's an isolated system. And it's energy-only
15 market where the prices can go very high, it can go to
16 \$9,000. Our load is mainly residential air conditioning,
17 which means that the majority of the time the load is quite
18 low. And during the summer peak it goes very high. So most
19 of the time our prices are very low, and then it goes -- it
20 can go up to \$9,000 in the summer.

21 We have a lot of renewable penetration which
22 drives the prices negative a lot of times. About two
23 percent of the time we see system-wide negative prices. And
24 recently we have started seeing negative prices during even
25 the morning times. Our gas -- our fleet is mainly natural

1 gas, so our prices are mainly determined by the natural gas
2 prices. So this year or last year, our prices have been
3 historically low. Over the last 15 years, it's been -- the
4 average price last year was \$24.60. So that has drastically
5 changed the generation pattern and market behavior in our
6 system.

7 If you go to the next slide?

8 This shows the amount of wind growth that we have
9 seen historically. You can see that there has been a
10 drastic increase in wind, right from the beginning of 2000,
11 and that we did a lot to surpass the renewable portfolios
12 requirement. The requirement was to go to 10,000 megawatts
13 by 2025, and we reached that by around 2010, and we are
14 still growing a lot.

15 Right now we are about 18 gigawatts of wind which
16 produces a peak output of about 16, more than 16 gigawatts.
17 And we have seen penetration up to 50 percent. The
18 prediction is that we will go to 24 gigawatts by the end of
19 this year. And there are signed interconnection agreements
20 which say we will go to 28 gigawatts by 2020. But in our
21 generation interconnection studies, we see another, on top
22 of all that, another 18 gigawatts under consideration. So
23 how much of those will come or not, we don't know. It all
24 depends on where the natural gas prices are and a lot of
25 other factors.

1 If you go to the next slide?

2 So all this means, with drastic increase we were
3 put into the middle of a lot of issues, and we had to work
4 to figure out how to address all those.

5 The first and the foremost issue that we faced was
6 the condition management. We didn't have enough
7 transmission to support the wind that came. Most or almost
8 all of the wind initially came in the West Texas area, and
9 our load was mainly in the east side. So transferring power
10 from the west to the east was a big problem. And so the
11 PUCT put out a rule to study and build out transmission,
12 that was major, but right from the beginning. So there was
13 agreement that we need to curtail the wind.

14 There was a lot of discussion about it, about who
15 will get curtailed first. And people wanted to not get
16 curtailed if they were the first ones coming. But the
17 discussion finally approved was that all the wind resources
18 are required to offer into the market. And they are -- if
19 they don't submit an energy offer Energy Offer Curve, we
20 will create an Energy Offer Curve at minus \$2.50, and we
21 will economically dispatch them and curtail them to manage
22 the condition.

23 And one of the biggest things that we did was we
24 implemented our real-time market to run every five minutes
25 right now for the next five minutes based on the current

1 wind output. So we don't use any wind forecasts, so
2 forecast error doesn't come into the picture in our real-
3 time market. And we economically dispatch these wind
4 resources. And if they don't follow the curtailment signal,
5 if they generate more than the curtailment signal, we put a
6 penalty for them. So there is a base point deviation
7 charges for even wind resources if they (indiscernible) the
8 curtailment. That was the initial step.

9 Once we put that curtailment, we started seeing
10 other problems. As soon as the wind resources are
11 curtailed, they'll drop like that and the frequency will go
12 down. And when they are released from curtailment they'll
13 go up and the frequency will go up, so we started seeing a
14 lot of frequency problems. So we said you cannot just ramp
15 so fast, so we put in a ramp requirement for wind resources.
16 Initially, we put in that wind resources, when they are
17 curtailed, are released from curtailment. They can only
18 ramp up to ten percentage of their pMaX per minute. Now it
19 is relaxed to 20 percentage of their pMaX per minute. So
20 it's a ramp restriction, how fast they can change so that it
21 doesn't affect the frequency.

22 On top of that, we also put that wind resources
23 need to provide primary frequency response. And there was a
24 lot of opposition from people who had already built their
25 technology. But -- so I think there was some

1 grandfathering. But most of the wind resources now provide
2 primary frequency response, that's that if they are
3 curtailed and the frequency is low, then they automatically
4 release from curtailment and go up. And if they are not
5 curtailed and the frequency is high, they will curtail
6 themselves to maintain the frequency. So they provide
7 primary frequency response.

8 Then the next thing that we did was ancillary
9 service changes, because we started seeing ramping issues
10 and other frequency problems. So we looked at whether we
11 need to change our current ancillary services to incorporate
12 the changes in the wind.

13 The first one was regulation, that is the
14 frequency following the five-minute one. So we look at net
15 load variability of wind -- net load variability. And we
16 procure regulation to meet 95th percentile of historic net
17 load variability as for regulation. And then we procure
18 non-spinning reserve to meet forecasted net load error. So
19 we look at net load forecast error for three-hour-ahead
20 forecast and we buy that as a product. And that gives
21 economic signals for generators to participate. And most of
22 the resources that participate in that non-spinning market
23 are fast-starting quick-start resources that can start in
24 ten minutes.

25 The other things that we implemented for wind were

1 voltage, ride-through requirement, reactive power
2 requirement. The things that are still being evaluated and
3 monitored are flexibility and inertia. Flexibility, from
4 the perspective of ramp available, not the frequency
5 responsiveness, the ramp availability, I would say we were
6 quite lucky right from the beginning that 50 percentage,
7 more than 50 percentage of our generation fleet is natural
8 gas. We have more than 6,000 gigawatts of resources that
9 can start within 30 minutes, of which 3,000 gigawatts can
10 start in ten minutes. So we are already good -- we already
11 have good flexibility. Now the non-spin product that we
12 have gives them the money to sustain those resources there.
13 And those ten-minute start resources actually are available
14 for commitment in real-time in the five minute dispatching
15 market.

16 And then we do rely on reliability unit
17 commitment. We evaluate commitment needs every hour based
18 on the next remaining hours in the day. So we study the
19 remaining hours in the day every hour, and we do
20 commitments. Even though we have that ability to commit
21 every hour, we still procure this non-spin, which is kind of
22 a flexibility product. It will account for the net load
23 forecast error.

24 Then another incentive is the \$9,000 price spikes.
25 Any time we run out of ramp, any time, in our system, prices

1 go up, almost all the time it is because of us running out
2 of ramp. So those price signals, it can go pretty high
3 pretty fast. That sends the signal for resources to be
4 available, and distributed resources to be dispatchable. We
5 have seen distributed generators starting up when the prices
6 go about \$200, so we have seen a response to the price
7 spikes.

8 Now we know that there is uncertainty and
9 availability. So we implemented a new desk in our control
10 room to look just at risk introduced by the renewables.
11 What we look at is available ramp capability. We look at
12 probabilistic ramp, forecasted ramp for loads, net load
13 forecasts, wind forecasts, solar forecasts. We have five
14 minute -- we are getting five minute wind forecasts. So all
15 those forecast errors for -- based on historic errors that
16 we have seen, we look and see if we can commit generators
17 and meet the need, if we end up having a worst case error
18 for forecast. We look at probabilistic ramps. Then we look
19 at inertia availability.

20 So in our system we are required -- we require the
21 generators to tell us where they are going to be or
22 commit -- where the commitment is. So based on their
23 commitment, we track how much ramp is available and how much
24 inertia is available. And based on that and possible
25 errors, we do more commitments.

1 Now with respect to inertia, we did studies. And
2 initially we thought we might have a lot of problems, so we
3 looked at changing our ancillary service to introduce a new
4 product, inertia product. Based on some of the economic
5 analysis that we did we saw that the prices might
6 incentivize more combined-cycle generators to come. And if
7 combined cycles and CTs are the ones that are coming in the
8 future, that might provide the support, inertia support that
9 we need. Basically, inertia is kind of the ability of the
10 power system or the synchronous-connected generators to
11 prevent the frequency decay. So as Clyde had said, if you
12 have fast-start resources that can prevent the initial rate
13 of change of frequency, then it might be enough -- or it
14 might be helpful if you have less inertia.

15 Now (indiscernible) is a highly interconnected
16 system, so you might not have that problem. We are a
17 separate island, so we have a problem. So what we are
18 trying to do is to have a constant watch on what inertia
19 levels we have and see if we are declining in the coming
20 future, and then introduce that as an ancillary service.
21 Right now we don't see a problem. But if we see a problem,
22 we'll introduce that as an ancillary service into the
23 market.

24 If you go to the next slide?

25 So this is a quick graph which shows the change in

1 solar that we are seeing. So you can clearly see that solar
2 is increasing almost the same way as wind. It is in the
3 initial stages.

4 So what we have done is all the requirements that
5 we have put for wind, we have put for solar, as well, so
6 economic dispatch based on deviation, voltage, ride-through
7 reactive power requirements, primary frequency response,
8 everything. We have put forth solar, as well, but we'll
9 have to wait and see if there is any problem that we see
10 because most of our long-term assessment studies have shown
11 that any scenario we take, the new generation addition that
12 we are seeing is mainly solar. We're hoping that all these
13 rules that we have put would account for it.

14 And that's all I have.

15 MR. BARKER: Thank you very much.

16 So what we'll do, and just a reminder, feel free
17 to take your nameplate, turn it on its side. We have a
18 couple sort of high-level questions, I think, actually. In
19 your initial remarks you touched on a lot of these. But if
20 you'd like to dive in a little bit deeper on some of these
21 questions, it will be good. So we'll take the next ten
22 minutes or so to go over this, and then leave the last ten
23 minutes for questions from the dais.

24 So the first question, and this can be for
25 technology, it can be for markets, it can be for, you know,

1 regulators or any type of regulation, anything of above, but
2 what's the biggest recent change or development in sort of
3 this space that maybe -- that has affected you?

4 Okay, go for it. Yeah, it's all -- you're good.

5 MR. MODY: I think a couple of the asset owners
6 actually touched on this, is how to keep assets that provide
7 a valuable service to the grid online? What's -- how do we
8 add value to it? And one of the examples, we saw that, and
9 Matt, I know you kind of touched on regulated rate recovery
10 being maybe a reason this could have been done, is for
11 Southern California Edison, they recently put a project in
12 the ground that combines energy storage with LM6000s. So
13 LM6000s that have been very flexible assets, providing a lot
14 of ramping capability, providing spinning reserve capacity
15 to the system, now can offer that service without burning
16 any gas, which I think ends up being a win-win for the
17 entire system.

18 Then the question really becomes, how does the
19 market provide a signal to incent this investment? And I've
20 be very curious to hear some of the asset owners opinion of
21 this.

22 MR. BARMACK: I mean, I guess I'll take that. I
23 mean, the short answer is it doesn't, you know? And Edison
24 or PG&E can do things and justify certain investments
25 through its regulators in a way that we can't. You know,

1 maybe there would be a market for some of these upgrades if,
2 you know, instead of just doing these upgrades to utility-
3 owned generation, if one of the utilities opened up a
4 competitive solicitation for upgrades.

5 But as far as the markets that we can access
6 easily, you know, like the CAISO energy and ancillary
7 services markets, and the resource adequacy market, there
8 isn't a signal for the type of upgrades that Amol just
9 described.

10 MR. THEAKER: Kevin, it's Brian Theaker with NRG.
11 Thank you for not making me put my placard up.

12 MR. BARKER: Yeah. No, that's fine.

13 MR. THEAKER: I appreciate that.

14 So I would answer your question this way, I think
15 the biggest development hasn't happened yet, at least in
16 terms of solutions. I think we're on the cusp of it.

17 What I think the big development is that's
18 spurring this conversation is the dramatic increase we've
19 seen in the flexibility requirements. I mean, if you were
20 to go and look at the ISO's 2018 flexibility capacity
21 requirements and compare them to '27, the change is
22 breathtaking. In some month, particularly in the fall
23 months, there's an increase, you know, in the range of 30 to
24 40 percent above what we saw in '17.

25 So we currently -- again, we have a glut influx.

1 We have -- the system is very long. The ISO is trying to
2 address that. And I think that until we have a natural
3 shakeout in the market, you know, the situation -- as well
4 as some change in contracting and procurement, the situation
5 Matt described is going to continue, which is there's just
6 going to be no economic signal for this, but hopefully that
7 will change over the next few years.

8 Go ahead, Kieran.

9 MR. CONNOLLY: I forgot to turn myself back on.

10 Actually, I agree with Brian. I think we are kind
11 of on the cusp of the big change that's happening now. And
12 I think with the pace of renewable development picking up
13 and the abundant hydro year that we're all having here on
14 the West Coast, I think we're seeing what we've all known
15 was coming start to materialize before our eyes, and that is
16 the realization of the flexibility need, and the challenges
17 in sort of the traditional marketplace that have been slowly
18 manifesting for quite a long time.

19 So I think it is motivating everybody, and that's
20 one of the reasons why we're all in the room today. And so
21 I think the wheels are turning. We've had great engagement
22 with folks at the CAISO and elsewhere in the industry about
23 this. But I think now the challenge before us is, though,
24 is what is that transformational leap we do to bring both
25 existing and new resources to bear on these issues?

1 MR. BARKER: So, yeah, go ahead.

2 MR. CONNOLLY: One last thing I was going to
3 say --

4 MR. BARKER: Yeah.

5 MR. CONNOLLY: -- is, you know, this is -- while
6 it's new, it's also old; right? I mean, California used to
7 be our source of oversupply disposal for decades. So, you
8 know, we've had this in different forms in our past. And so
9 I think it is the question of how do we adjust now for a
10 more complex, certainly, but -- and bidirectional form of
11 this challenge? Because, you know -- and it's not simply
12 renewables integration in California radiating out; right?
13 We're growing renewables in the Pacific Northwest. Other
14 folks are, as well. So it's how do we bring all of these
15 things together as a region.

16 MR. BARKER: Go ahead, Resmi.

17 MS. SURENDRAN: Yeah. So I have seen some
18 research where people have said that the invertors can
19 change and be grid -- instead of grid following, grid
20 shaping. And whether that is coming in the near future or
21 not, there is some development on that side. So if that is
22 going to materialize, then you can be like 100 percent
23 renewable, and the invertors can provide all the synchronous
24 resource-supported typical conventional generators are
25 providing.

1 MR. BARKER: Do you want to add something, Brian?

2 MR. THEAKER: Yeah. Thanks.

3 MR. BARKER: Sure.

4 MR. THEAKER: Brian Theaker with NRG.

5 I'd also offer that one of the biggest things
6 we've seen is we've seen the growth of renewables and the
7 operational challenges really impact operations in ways that
8 we hadn't anticipated. You know, on April 24th, Tom noted
9 that the ISO believes they have seen hydro operators choose
10 to spill the water rather than, you know, put it through the
11 turbines, which is kind of breathtaking in terms of the fact
12 that we've always tried to make the most economic use of
13 this resource. But that fits, because if you look at the
14 number of negative price intervals for April, the number for
15 March 2017 was much higher than we saw in 2016. And I think
16 that everybody expected to see the April number just blow
17 past that. And, in fact, there were fewer negative price
18 intervals in April than there were in March.

19 So I think that's, Tom, I think that's, you know,
20 kind of indirect testimony to what you offered as how the,
21 you know, operators are responding to these challenges.

22 So I do think that, you know, another big thing is
23 that we have seen -- we are now seeing how these things
24 effect operations, not in a theoretical sense but in a real
25 sense.

1 MR. BARKER: So one thing, I guess, that poses a
2 question, if -- so if we're on the cusp, if you will, of
3 needing -- knowing that we're going to need and have a
4 process to realize how to get these flexible resources, do
5 we already, the processes, the rule makings, the other
6 things that are happening at the different agencies, do we
7 have -- are those all set up? You think that they're moving
8 along at the right trajectory, knowing that things are
9 coming a lot quicker than we thought, or if you had, and not
10 to throw anyone under the bus, but if had a recommendation,
11 or two, of how it can be improved, what would you say?

12 Go ahead, Josh.

13 MR. NORDQUIST: I guess since I don't live in
14 California I can say it's really complicated here. But
15 that's -- I think that's not an excuse by any means, because
16 it should be stated, it's well known and it was touched on
17 many times here today, you know, this is the, in many cases,
18 the biggest and the first time this is going through, and
19 that's significant. I think there's no other -- if there
20 was another book we could put next to it and say, well,
21 we'll just do it that way, it would be a lot simpler.

22 But in reality, and, you know, I think ERCOT is
23 even an example, as well, that -- on how the system runs,
24 though it's not -- it's similar but not the same. Being its
25 own island and having to, you know, in many cases forcefully

1 figure out these solutions very quickly, we have a different
2 opportunity. We have an opportunity to look outside borders
3 and look into the region for a bigger solution, which
4 inevitably has to involve the other regions. And I think,
5 even though the process is complicated and, you know,
6 requires a staff of people just to watch, it's needed.

7 If I had an answer to simplify it, I think if I
8 threw it out there I wouldn't be in the renewables market
9 anymore. So I guess my quick answer is that it's -- so I
10 don't want to be (indiscernible) that we -- that there has
11 to be a different way to approach it, because at the same
12 time, in many cases, it's the first approach. And sometimes
13 that takes -- sometimes that takes a little longer and is a
14 little more complicated, no matter what.

15 MR. BARKER: Go ahead, Matthew.

16 MR. BARMACK: I'll comment on a couple things.

17 You know, first of all, I think I'm probably less
18 optimistic about flexible RA than Brian is. So I think
19 there's sort of a perception that we're going to keep
20 working on flexible RA and eventually that's -- you know,
21 we'll get to the right answer and that's going to solve all
22 our problems and lead to the procurement of the right
23 resources. I mean, we've been at this for a long time. And
24 it doesn't appear that we're any closer to a real solution.

25 You know, in the meantime, you know, we're losing

1 a lot of the conventional generation fleet. And, you know,
2 repeatedly, we and others have put forward proposals for,
3 you know, more forward procurement to, you know, lock down
4 some of the resources that are really necessary to secure
5 reliability. And, you know, sort of the pushback on that
6 has been, oh, you know, first we're going to figure out
7 flexible RA, and then maybe we can have forward procurement.
8 And I think maybe we need to separate those two problems a
9 little bit and start thinking about, you know, securing
10 certain assets that we know we're going to need, for
11 example, certain resources in local areas. You know, I
12 don't think the resolution of all -- you know, what our
13 flexibility needs are really going to materially impact what
14 we procure to meet local reliability requirements.

15 You know, secondly, with respect to IRP, you know,
16 I thought Ed gave a great overview of IRP and how it's going
17 to, you know, determine the whole resource mix that we're
18 going to -- that we're going to need to meet our GHG and
19 other goals. And, you know, existing conventional
20 generation is clearly part of that mix.

21 What I would point out is pretty much every other
22 resource in that mix is secured through some sort of long-
23 term commitment. And I think, you know, sort of similar to
24 my earlier comments, I think there needs to be some sort of
25 term commitment to the existing conventional generation

1 that's recognized to be part of the plan, you know, to meet
2 the, you know, 2026 and the 2030 goals, just to make sure
3 that those resources are actually there if we're counting on
4 them.

5 MR. BARKER: So one last question. And, you know,
6 I think we've, again, touched on this. So if there -- if
7 you don't have any additional comments, I think that's fine.

8 But if you were to say for -- and, you know,
9 everyone is a little bit different here, what would be the
10 biggest barrier? And then also what actions or action would
11 be needed to overcome that?

12 Go ahead, Brian.

13 MR. THEAKER: Yeah. Thanks, Kevin. I'll just --
14 I'll dovetail. I can't help, after Matt's excellent
15 remarks, I think the biggest barrier is kind of the
16 uncertainty around what's going to happen with the
17 conventional fleet. And, you know, Matt made a compelling
18 case that every other resource out there has got a
19 procurement horizon that stretches beyond just the single-
20 year RA program, which has been, you know, reserved for the
21 conventional fleet. So I think that addressing that is our
22 biggest hurdle going forward.

23 MR. BARKER: Kieran?

24 MR. CONNOLLY: So for us, I think it is we think
25 we have existing flexibility that we can bring to bear now.

1 So having eligibility for that and a day-ahead product that
2 would fit with our need to manage risk on the hydro system
3 we think would provide some real access to California in the
4 short term.

5 MR. BARKER: Yeah, please, Amol.

6 MR. MODY: Yeah. I'll jump in and kind of
7 piggyback on the earlier comments.

8 From a technology perspective, we have a lot we
9 can offer to the marketplace. We have a lot we can offer to
10 asset owners, both on the conventional and the renewables
11 side. And I think what I'm hearing from the market
12 participants is that market signals are necessary. I think
13 GE continues down the belief of a diverse set of resources
14 is necessary to address the system's problem moving forward,
15 and we're ready to help you guys get there.

16 MR. BARKER: Okay. With that, I'd like to,
17 please, turn it over to the dais, please.

18 CHAIR WEISENMILLER: Yeah. Let me start with a
19 couple of observations. I mean, first, I really want to
20 thank ERCOT and BPA for being here today. It certainly
21 helps on a perspective, and I appreciate you coming.

22 I think it's sort of weird, we're talking about
23 digitalization today as being part of the solution, but
24 we're having the world's greatest cyber-attack at this very
25 moment. And, you know, let's not -- let's take into account

1 that things can get pretty serious pretty fast as they are,
2 you know, in the U.K. and other places right now. So again,
3 I think people have to be pretty conscious of that.

4 On geothermal flexibility, I think a lot of it
5 comes back to the basic message, the issues are commercial.
6 You know, Tom Sparks, you know, basically, and I tried to
7 make the Geysers renegotiate the contracts with PG&E in the
8 late '80s and early '90s to make the geysers a flexible
9 resource, but we could not work through the contractual
10 issues.

11 You know, so again, I think a lot -- you know,
12 renewables, per se, yeah, have flexibility we haven't
13 unlocked yet, but -- you know, particularly the geothermal.
14 But again, a lot of it is commercial that we have to work
15 through.

16 I think, you know, the other general observation
17 is we've heard a lot about the conventional resources, once
18 their contracts are over. (Indiscernible) never got a
19 contract, but how do they survive? Actually, there's a lot
20 of renewables that were QF resources that are out of their
21 contracts that have -- you know, they may have a different
22 cost structure. But certainly, you know, we're hearing from
23 them also in terms of how do they, you know, survive, you
24 know, be it the sort of existing wind, you know, that should
25 be repowered. But certainly there's no opportunity at this

1 point to deal with the contracting, you know, if you're
2 talking long-term procurement. So that's sort of a generic
3 issue as opposed to just the conventional fleet.

4 I think with BPA, so shifting more to some
5 specific questions, you know, with BPA, I really appreciate
6 how BPA has contributed in a very positive way as we've
7 moved forward on the Energy Imbalance Market. I mean, it's
8 been a very key partnership. And also I appreciate that BPA
9 is thinking as a hydro system operator much more about how
10 the transformations of the market affect them and how to
11 optimize their value. I actually would like to see more
12 creativity out of some of our California hydro system owners
13 than we've seen at this point, at least compared to BPA.

14 I guess the two follow-up questions are, one,
15 would BPA, on the DC tie, how fast can we start moving to
16 make that more flexible, and what would it take?

17 MR. CONNOLLY: Yeah. And this is outside of my
18 sweet spot of technical expertise, but I'll try to answer.

19 CHAIR WEISENMILLER: Sure.

20 MR. CONNOLLY: So it is a question of moving from
21 fairly manual operations today where we're relying on humans
22 and actually digitally connecting those DC operations into
23 our AGC. So we have a fair amount of modernization that
24 we're stacking up at Bonneville that we're trying to do for
25 these reasons and more. And certainly, this is one of the

1 things in the queue. It will also take -- our friends in
2 L.A. will have similar challenges, is my understanding. And
3 so we'd have to work them on working on the timing, right,
4 because doing this on one side isn't going to solve the
5 challenge.

6 But lastly, I would say that it will come back to
7 the, at the end of the day, the commercial demand for those
8 kind of short-term flows. You know, as a transmission
9 provider, obviously, we'll have to -- we have to figure out
10 how to queue that up. Because if it's a theoretical
11 capability but folks that own the transmission are not
12 looking for that service, then it will be slower to come
13 than it will if folks are looking for that. So it's kind of
14 those components.

15 So I can't give you a clear answer, just because I
16 know it's one of the things in the portfolio that we're
17 trying to optimize, but all of those issues are in play.

18 CHAIR WEISENMILLER: Okay. I mean, actually, it's
19 a little scary, because the LADWP is legendary for its IT
20 problems. But anyway --

21 MR. CONNOLLY: I'll leave them to answer that one.

22 CHAIR WEISENMILLER: The other question is how do
23 we start, you know, going to shorter and shorter periods on
24 scheduling on the intertie? You know, again, it's sort of I
25 know we're talking 15 minute, but five minutes? I mean, how

1 fast can we really start moving in that direction?

2 MR. CONNOLLY: Well, you know, so we have a lot of
3 15-minute capability on the AC today that isn't fully
4 utilized. And our folks are concerned about these
5 oscillation risks of going too far into five minute on the
6 AC. So that is a technical barrier that we see and we're
7 still working on it. But that is -- we think there are some
8 reliability risks there, so we are going to be cautious
9 about pushing that. Now, we have some tools, because we do
10 know that this is one of those things that ebbs and flows
11 based on system conditions. So we're at least trying to
12 figure out how we can widen that pipe when it's safe to do
13 so, but also clamp it down when we need to for reliability's
14 sake.

15 Going back to my earlier comments, you know, we
16 really think that there is some merit in looking at your
17 flexibility needs and sort of stacking it in over time so
18 we're not forcing everything into that five-minute
19 increment, because we think that that unduly ties you up in
20 knots, both from a transmission perspective and because of
21 the complexities it puts back on the largely hydro in the
22 Pacific Northwest that's trying to come down there anyway,
23 because we think you'll get it at a lower cost if we can
24 sort of disassemble that problem into a longer run and a
25 shorter one.

1 CHAIR WEISENMILLER: Yeah. I mean, certainly, you
2 know, historically, you know, even going back to when I was
3 young, anyway, a lot of seasonal exchanges were a lot of the
4 transactions we were doing. And the question, it seemed to
5 be phrased by the more recent work Bonneville is putting
6 out, is how do we get more into exchanges at this point on a
7 daily or whatever, you know?

8 So part of it again is what would it take for you
9 and the ISO to start marching through some of that
10 transformation?

11 MR. CONNOLLY: Yeah. Well, I think on the daily
12 exchanges, ramping products, I think it comes back to a lot
13 of the things people here have been talking about. It's the
14 what is the product design and sort of the commercial terms
15 more than it is a technological problem, once we step away
16 from sort of ramming things into the five-minute market?

17 CHAIR WEISENMILLER: Now as I understand, you had
18 a very adverse court ruling on fishery issues last spring.
19 What's the current status? I mean, as we try to integrate
20 things, you're going to have to go through incredible
21 transformations, I think, on the fish to respond to those
22 court rulings.

23 MR. CONNOLLY: Yeah. And we're still in court, so
24 I'll keep my comments brief. But we did have an adverse
25 court ruling. It does mean more spill, less production from

1 our system in the spring. Now that is a time when we're
2 typically very long to begin with. And we are working
3 through what, if any, implications there are for the
4 flexibility of our system. But this is really -- and
5 certainly it is an impact for Bonneville, but it is
6 something that we've been dealing with for some time, so we
7 don't see it as -- from an operational perspective, we don't
8 see it as an extreme impediment. There are some conditions,
9 particularly in low water years where we have some concerns,
10 and we're working through those with the Corps of Engineers
11 and NOAA. And we'll be working with the court on how we
12 implement to avoid those challenges.

13 CHAIR WEISENMILLER: Yeah. Probably my last
14 question for you. But as I said, in the first Brown
15 Administration, we really started the process to look at the
16 intertie sizing. And a number of us had the impression that
17 we really weren't capturing the sort of higher hydro that
18 came in some high hydro years. And that ultimately resulted
19 in the TANC project. It took that long, at least, you know,
20 ten years to come up with that. And, obviously, the original
21 interties were really optimized in the '60s, you know, when
22 power prices were phenomenally different than what they are
23 now. And so that was -- those intertie upgrades then were
24 phenomenally, you know, the TANC, et cetera, became very
25 cost effective.

1 So I guess part of it is to start encouraging the
2 ISO and BPA to start thinking about, given current
3 conditions, what makes sense in terms of potential upsizing
4 there.

5 MR. CONNOLLY: Right. And certainly recently
6 we've completed some upgrades on the DC to enhance its
7 capability. And so, you know, yeah, we'll continue to look
8 at those things.

9 CHAIR WEISENMILLER: Yeah. Thank you very much
10 for coming out. Now on the ERCOT perspective. I think,
11 again, it's fascinating, when you look at California really
12 dominates the U.S. market on solar, we're like 50 percent.
13 You know, geothermal, god bless, you know, we're, you know,
14 what, 90 percent? Anyway, again, we're the geothermal
15 market, certainly the biomass market.

16 But I mean Texas, relative to California in wind,
17 has just blown us out of the water. So anyway, it's good to
18 get some competition going.

19 I think, you know, sort of, in terms of your sense
20 of, as you start adding more solar or looking at our
21 experience, again, what do you see as the major problems you
22 have to deal with the next five years?

23 MS. SURENDRAN: So we are seeing all of our long-
24 term system assessment studies have shown that solar is the
25 one that is coming, and it's ranging from 14 gigawatts to

1 like 30 gigawatts of solar addition by 2030. So we think
2 almost the same type of problems will come with the wind,
3 whatever, we have seen. So that's why right away we have
4 already put in almost the same requirements for solar, so
5 hopefully those kind of problems will not come.

6 Now there's a difference between California and
7 ERCOT in the distributed area because we have very high
8 retail competition. And our retail rates are very low, so
9 distribution-level solar is non-grid parity, even at this
10 point. And if more utility-scale solar is coming, then we
11 don't -- then the prices will even go down, so we don't see
12 that level of penetration in the distribution level.

13 If we see that level of penetration, then we think
14 there will be a lot of problems for us, for, I guess, for
15 everyone about the visibility and controllability of the
16 distribution and other resources. So we are starting to
17 work with the stakeholders on looking at the reliability
18 problems from that, and maybe even looking at pricing those
19 distributed resources at an old level so we can have more
20 controllability of those resources. That's kind of the
21 biggest problem that we are thinking we will have if we see
22 a lot of distributed solar.

23 CHAIR WEISENMILLER: So Mark had mentioned CPS1. I
24 mean, what do you see as the key reliability metrics that
25 you're trying to stay on top of?

1 MS. SURENDRAN: So for CPS1, if I understand
2 correctly, is an average value. And we did see a decrease
3 in CPS when -- at the initial time when wind started coming
4 in. But after putting in the primary frequency requirement
5 and ramp requirement for wind resources, our CPS score has
6 increased. And now it is about like 180 or so when the
7 required value is 100. So the market participants are
8 telling us we have too much reliability, so we don't see
9 that problem.

10 The reliability problems we are thinking might be
11 from fault control. If distribution level resources are
12 there, then I think backflows and like voltage controls,
13 reactive or controls problems. And then I think lower -- if
14 there is a fault there can be problems in the distribution
15 level if we don't set voltage and reactive standards for
16 those resources. That is kind of a problem that we are
17 thinking might be there.

18 CHAIR WEISENMILLER: Okay. Have you had any
19 reliability problems at all as a consequence of the
20 renewable additions to your system?

21 MS. SURENDRAN: In the beginning, with a lot of
22 frequency variation. So our CPS scores were like if you
23 look -- if you plot our CPS scores, you can see, it goes
24 like this.

25 CHAIR WEISENMILLER: Okay.

1 MS. SURENDRAN: So there were (indiscernible), and
2 then we increased. And each of the time we implemented -- I
3 think the first increase was when we put the frequency
4 requirement. Second was when we put the ramp requirement.
5 Third was when we put the deadband, we tightened the
6 deadband. Because we are an island, we require all the
7 resources to provide primary frequency response. And we
8 have a five-percent troop (phonetic) characteristics for all
9 of them, so we tightened the deadband for all of them. That
10 increase held down frequency.

11 We haven't seen other big problems.

12 CHAIR WEISENMILLER: Do you have much storage or
13 any storage on the system?

14 MS. SURENDRAN: No. We have seen some interest in
15 storage, and they are there in our generation
16 interconnection study. But it gets delayed and delayed and
17 delayed because it's not economical based on the current
18 market prices in ERCOT.

19 CHAIR WEISENMILLER: Thank you.

20 MS. SURENDRAN: Uh-huh.

21 COMMISSIONER RANDOLPH: I had a question, kind of
22 following up on Matt's comment about sort of flexible,
23 durable products. And that's sort of been talked about for
24 a couple years now as a potential solution without a huge
25 amount of progress. So I'm curious to hear your thoughts,

1 and maybe Tom's thoughts, as well, about what you see as
2 kind of the barriers in getting to that point?

3 MR. BARMACK: I'll go first. And, you know, first
4 of all I just want to say that, you know, CAISO and PUC
5 staff who have been working on this are very able and very
6 well intentioned. It's just turned out to be a very
7 difficult problem. And, you know, part of it is, you know,
8 we're basically trying to capture the complexity of
9 operational reality where, you know, sort of different
10 operating characteristics of a unit, sort of interact with
11 one another, and different resources interact with one
12 another in a complex way. We're trying to distill that down
13 to something that's very simple and can be procured on a
14 year-ahead or more forward basis.

15 And, you know, it just turns out, technically,
16 that's very difficult. Nowhere else in the world has done
17 it. You know, you've heard today, there are other markets
18 with very high penetrations of renewables that have, you
19 know, tried other approaches, like relying more on the
20 energy and ancillary services markets.

21 So, you know, I'm not saying it can't be done. I
22 think good work is being done. I'm just concerned about
23 timing. And, you know, the way things have been going
24 lately, the latest proposals that are out there are really
25 for another interim product that might be out there for a

1 few years until some, you know, more permanent solution is
2 developed. And I feel like that's sort of the same place we
3 were in about two or three years ago. And so that's really
4 driving my pessimism about a rapid resolution.

5 And, you know, in the meantime there is a lot of
6 distress in the conventional generation community. And, you
7 know, I'd be the first to acknowledge that some
8 rationalization of the fleet needs to occur. But, you know,
9 I would like that rationalization to occur rationally. And
10 I just don't -- I don't -- I just don't think that, you
11 know, flexible RA, no matter how good it might ultimately
12 be, is going to facilitate that process in the next few
13 years, and there is going to be distress soon.

14 MR. DOUGHTY: Commissioner, we tend to agree with
15 Matt's viewpoint. There is a level of complexity in this
16 that really has not been pioneered anywhere else. And we
17 have a need to avoid making this product too complex.
18 Everybody who works in the ISO market knows it's very
19 complicated. So in a complicated setting, one of the most
20 difficult things you can do is to try to de-complicate. It
21 sounds rational and irrational at the same time, doesn't it,
22 Matt?

23 So, you know, we've got to get these OTC units out
24 of the mix. We've got to move through this sequence that
25 these folks have talked about. This next wave that we've

1 talked about is not yet here and we've got to move through
2 that. We remain optimistic that we're going to be able to
3 deliver that product. But to Matt's point, it is a very
4 difficult discussion.

5 COMMISSIONER MCALLISTER: Yeah. So I would sort
6 of ask an analogous question to Commissioner Randolph about
7 demand response. You know, we've been talking for more than
8 two years, more than a couple of years, about that. There
9 are some products in place. There's, you know, there is --
10 a lot has actually been done, but it's sort of an ongoing
11 frustration that we don't have more scale in demand
12 response.

13 And I think certainly as we get renewables
14 penetrating, as we get -- as we're considering longer term
15 investments about how to -- you know, what our grid of the
16 future is going to look like, personally, I think it's
17 really important that we do everything we can to get demand
18 flexibility and to help us match, you know, supply and
19 demand in a way that isn't hardware intensive but is
20 actually just smart in behavior, takes advantage of behavior
21 change and the wonderful digital technologies that we have.

22 So I guess I really want to ask the question to
23 BPA and to ERCOT, you know, what's your experience with
24 getting demand-side flexibility, say, you know, water
25 pumping buildings? I mean, I think, you know, there's a

1 huge potential that we're not -- that's not tapped in
2 buildings. You said you have a lot of AC load, obviously.

3 Are the mechanisms you have in place for demand
4 response, you know, there and working, and what kind of
5 challenges or activities are you engaged in, you know, to
6 try to address that and scale it up?

7 MS. SURENDRAN: So we, in general, want to attract
8 all type of investments. So as part of that, we are always
9 looking at what market design changes can be done. And so
10 we have made all our products and all energy, every market
11 open to demand response, as well. So our real-time market
12 also has the ability for demand response to participate, but
13 we haven't seen much in real-time. But we have seen a ton
14 of activity in the ancillary service market. We have about
15 1,500 megawatts procured on -- I think 1,000, yeah, 1,100 or
16 somewhere around that range procured on a daily basis for
17 ancillary service, but then at about 3,000 megawatts of that
18 qualify to provide that. And that's the amount that Clyde
19 was earlier saying, which is responsive reserve service
20 which can deploy very fast and provide the frequency support
21 to help if we don't have inertia. That's one product.

22 Another is we have a service called ERS which is
23 required by our PUCT. It is not kind of an ancillary
24 service, but we have a \$50 million bucket allocated to
25 incentive the DR. And this is the last resort kind of

1 deployment, in case of emergency. And that has attracted
2 about 1,000 megawatts of DR. Now our \$9,000 prices have
3 incentivized a lot of DR, too. We are starting to see
4 distributed generators that are acting as DR. And we can
5 see them respond to prices when the prices go over \$200.
6 Now we have TDSP load management program, which I would say
7 about 300 megawatts or so. And then we have price
8 responsive demand which maybe about 700 megawatts or so.

9 The interesting, maybe I would say is an
10 unintended consequence of our transmission cost allocation
11 is the DR that we are seeing. Our transmission cost
12 allocation is done based on four-year consumption average,
13 consumption at four points, and then peak intervals of the
14 summer. And because our transmission cost has increased a
15 lot now, what we are seeing is a lot of DR responding to
16 that, a lot of industrials responding to that. And we have
17 seen last year about 1,500 megawatt come off, which is the
18 main portion of the industrial load coming off to avoid the
19 transmission costs.

20 So as Brian has said, if you create the incentive,
21 people will respond. But the prices are really high if you
22 look at the value of lost load for them, too.

23 COMMISSIONER MCALLISTER: Those are great
24 examples, especially the industry. Well, you know, it's
25 impressive.

1 So just following up on the DERs, is that diesels
2 that are turning on, or is it, you know, renewables that are
3 going on --

4 MS. SURENDRAN: So --

5 COMMISSIONER MCALLISTER: -- or self-gen that's
6 going offline, or what? What kind of demand response is
7 that tending to be?

8 MS. SURENDRAN: So we have about, I think 1,000
9 megawatts of distribution-level resources, of which only 200
10 megawatts is renewable. The rest is all fossil fuel,
11 generator starting on, and so --

12 COMMISSIONER MCALLISTER: Thanks.

13 MR. CONNOLLY: And for --

14 COMMISSIONER MCALLISTER: Yeah.

15 MR. CONNOLLY: -- for Bonneville, we're -- well,
16 first a little context. Historically, demand response has
17 been a bit of a challenge because Bonneville is a
18 wholesaler, and our customers are the retailers. They're
19 the ones who have the loads and the distributed resources in
20 their service territories. But we have had some successful
21 pilots that we're actually now trying to transition towards
22 actual commercial application and having those resources
23 sort of compete to meet our needs on both the power and
24 transmission side, alongside traditional solutions to
25 challenges.

1 So when Bonneville has a need, either on the power
2 side or on the transmission system, actually, we're trying
3 to make sure that we bring demand response into that
4 equation at the beginning of the conversation, as opposed to
5 at the end as sort of an afterthought. And we've had
6 successful work with both commercial aggregators and some
7 really successful work with a public aggregator that's come
8 together. And I think that's been useful in our context
9 because the public aggregator kind of understands our public
10 customers, and so they're able to work with them on those
11 loads.

12 Bonneville also has gone to some capacity pricing
13 that is more reflective of market than our historic rate
14 making was. And even though those capacity charges are not
15 necessarily very high prices, they are sending a price
16 signal. And I think that has helped our customers say, hey,
17 we want to get involved in this, as well. And so we've had
18 some really good -- now, this is in the, you know, 10, 20,
19 50 megawatt range that we've been doing heretofore. But
20 we've had some really good luck doing both peak shaving on
21 the power side of the business and congestion relief on the
22 transmission side. And we're really getting ready now to
23 try to leverage that to more meaningful large-scale work.

24 So that's kind of the status for us.

25 COMMISSIONER MCALLISTER: Thanks a lot.

1 MR. BARKER: So do we have any other questions?

2 No.

3 So I guess I would just note, Commissioner
4 McAllister, that that question felt like maybe it was a
5 plant that I gave you. Because not only -- because that --
6 actually, not only are folks appetites whet because it's
7 past 1:00 now and everyone is hungry for lunch, but we will
8 be discussing on panel two, right at two o'clock, we will be
9 having folks talk about demand response and in buildings.

10 So with that, we start promptly again at two
11 o'clock. Enjoy your break. Thank you.

12 (Off the record at 1:07 p.m.)

13 (On the record at 2:04 p.m.)

14 MS. RAITT: Let's go ahead and get started. So in
15 the afternoon, we'll have two panels. And then we will
16 close with public comments.

17 And so our first panel is flexible load and with
18 DR and storage. And Pam Doughman from the Energy Commission
19 is the moderator.

20 MS. DOUGHMAN: Hello. All right. So this is
21 about flexible load, demand response, and storage. And why
22 don't we have the panelists go and introduce yourselves, and
23 you can give a quick overview of your organization.

24 (Colloquy)

25 MR. BULLOCK: All right. Good to go now. So Jim

1 Bullock with Green Charge Networks. We are also part of the
2 ENGIE family, so a large independent power producer. Our
3 core business is energy storage, traditionally focused a lot
4 on the CNI behind-the-meter segment, but also working on
5 virtual power plants and in-front-of-the-meter energy
6 storage, so engaged in a lot of different market segments in
7 the energy storage space, both the United States and around
8 the world.

9 MR. DEVINE: Doug Devine, CEO of Eagle Crest
10 Energy. I'm here on behalf of Eagle Crest. And I've spoken
11 to the Commission before on the Eagle Mountain Pump Storage
12 project. Although, I was at a hydro conference last week,
13 and Shell Energy is developing a modular pump storage
14 project, calling it a water battery which they have not yet
15 trademarked. So I'm not sure if that will take place, but
16 water battery is now being talked about.

17 We are developing a 1,300 megawatt pump storage
18 facility in Eastern Riverside County. It is a brownfield,
19 closed-loop project, kind of unique, at least in the Western
20 United States. It's an old abandoned iron mine, and we're
21 using two of the pits for our water storage. Because of the
22 size of the pits, it's a 1,300 megawatt. And we have 22,500
23 megawatt hours of storage, so the equivalent at kind of full
24 output of about 17 hours of storage.

25 We received our FERC license in July 2014 and have

1 all major permits, except for some BLM rights-of-way over
2 part of our transmission line, which we hope to get by the
3 end of this year.

4 MR. GEORGE: Hi. I'm Steve George, Senior Vice
5 President at Nexant. I have been studying consumer behavior
6 in the electricity industry for 40 years. I began my career
7 here at the California Energy Commission in 1976. I was
8 staring at the sign behind Bob's head there saying 1975. I
9 started in year two and building the first then used
10 forecasting models for the Commission, and I'm still around.

11 And today -- I got a phone call about 5:30 on
12 Tuesday night from SMUD saying could I come here and talk
13 about the SMUD TOU pricing pilot. And I said, "I'm off the
14 next two days, do I have to do any prep," and they said, no.
15 So I'm here kind of spontaneous with no slides, but I'll see
16 what I can share with you, and hopefully it will be
17 interesting.

18 MR. MURTISHAW: Hi. I'm Scott Murtishaw. I'm an
19 Energy Adviser to President Picker at the CPUC. And since
20 Steve is here, he can also just talk about the TOU pilots. I
21 don't really need to be here. I think he could just cover
22 it all because Nexant was the consultant to the investor-
23 owned utilities on the opt-in pilots that I'll be talking
24 about.

25 MS. BROWN: And I'm Linda Brown with San Diego Gas

1 & Electric. I'm the Senior Director of Clean
2 Transportation. And I'll be talking about electric vehicles
3 and the flexible load that they bring to the grid.

4 MS. DOUGHMAN: Okay. Great. So a couple
5 questions to start out.

6 Can you talk about the current status of your
7 technology that your organization works with or your
8 regulation that you're working on, and the biggest recent
9 change or development?

10 MR. BULLOCK: Yeah. I figured out the microphone
11 now, so I'm ready to roll.

12 So I think some of the big changes that we're
13 seeing in the battery storage industry, the efficiency and
14 costs, obviously, are coming down a lot on the actual
15 battery side, but not only on the batteries, also on the
16 entire module and the entire system. So when you look at
17 the systems, they're becoming very modular. They're fully
18 wrapped a lot of times and warrantied by vendors. So we're
19 seeing a lot of commoditization in the market and a lot more
20 efficiency in those.

21 Additional, we're seeing mandates across
22 California, as well as around the country. So, you know,
23 with things like AB 2514 and 2868, that's really been
24 pushing the market and helping it scale and really proving
25 out these technologies. So utilities are evaluating the

1 soft and hard benefits of battery technology. And it's
2 proving to be a viable technology and becoming closer to
3 parity at price point with other alternative technologies.

4 MR. DEVINE: Just a couple of comments on pumped
5 storage technology. Obviously, it has been around a
6 relatively long time in the power business. It is -- about
7 99 percent of all grid-level storage around the world is
8 pump storage.

9 Over the last two decades the Japanese started it,
10 and it's now spread to installations in Europe and elsewhere
11 in Asia, the adjustable speed technology which allows you to
12 provide variable speed pumping and allows the new pump
13 storage projects to provide a full suite of ancillary
14 services in both the pump and generation mode. In wide
15 dispersion, there's more than 200,000 megawatts in operation
16 around the world. Over the last ten years, China has put
17 over 10,000 megawatts in operation and are currently
18 constructing the largest pump storage project in the world,
19 which will be approximately 3,600 megawatts outside of
20 Beijing.

21 Obviously in California there are a number of
22 pumped storage projects, most notable, perhaps Helms and
23 Castaic, as well as some smaller projects. And I begin to
24 think pump storage is well suited to be a part of the suite
25 of solutions that Mark talked about earlier in this

1 morning's session about solving some of the issues we face
2 as we try and achieve our high levels of greenhouse gas
3 reductions.

4 MR. GEORGE: I'm not quite sure how to answer the
5 question since I'm not representing a technology. But let
6 me talk for a few minutes about time-of-use pricing.

7 I was also the key architect and evaluator of the
8 California Statewide Pricing Pilot, which was implemented
9 back in 2003/2004 where the three IOUs coordinated to see
10 what impact time-of-use pricing had. And this was a
11 precursor to all the AMI metering we now benefit from. And,
12 in fact, the results of that pilot were used to predict what
13 kinds of benefits you could get from time-of-use pricing as
14 input to the AMI business cases that led to the deployment
15 of, you know, what now there's probably 11 or 12 million AMI
16 meters in California on the electric side, and a lot of on
17 the gas side, as well. So, you know, that was a precursor.

18 And now we've got it where we're swimming in data,
19 but we still have some questions about time-of-use pricing.
20 And as I think everyone knows, you know, the CPUC is headed
21 in the direction of default time-of-use pricing deployment
22 starting in 2019.

23 As a lead into that, they implemented a new round
24 of TOU pilots, which I don't want to steal Scott's thunder
25 so I won't talk about that, but I can answer questions about

1 it. SMUD implemented their pilot in 2012 and '13, aided in
2 part by the ARRA funding from the Obama Administration. And
3 I think it's generally recognized as the best designed and
4 implemented pilot that had been done in the industry in four
5 decades. And I can say that because I didn't design it. I
6 got to evaluate it, so I can say that. And I think most
7 people would agree with that.

8 But it had a couple of very good features. First,
9 it was a very rigorous experimental design, randomized
10 control trials, randomized encouragement design. That gave
11 you great internal validity of your estimates. There's no
12 question about, you know, whether the measured or observed
13 impacts were statistically valid and internally valid.

14 But among the most interesting aspects of the SMUD
15 pilot was that they tested side by side opt-in and default
16 implementation using the same rates, so you could compare
17 what average impacts and aggregate impacts were based on
18 opt-in enrollment and default enrollment. And they also
19 tested multiple rate options, time-of-use pricing and
20 critical peak pricing and the combination of time-of-use and
21 critical peak pricing.

22 The key takeaways from the pilot, opt-out rates
23 were very low on the default side, both before enrollment,
24 so two to three percent of customers that were notified said
25 you're going to go on this new rate, unless you tell us

1 you're not, you don't want to. And only two to three
2 percent of the customers across the different treatment
3 cells opted out before they were enrolled on the rate. And
4 then over the next subsequent two years, between five and
5 eight percent of customers opted out. So the opt-out rates
6 were very low on the default side. They were actually lower
7 than they were in the opt-in side. On the opt-in treatment
8 cells more people opted out. But, you know, the logical
9 explanation of that is that, you know, part of default
10 pricing is that not everybody is aware that they have the
11 option of opting out, so you do get this inertia effect.
12 But anyway, opt-out rates were very low on both sides.

13 In SMUD's case, opt-in rates were very high.
14 They, in a single recruitment season, they were able to
15 recruit between 16 and 19 percent of the customers they
16 reached out to enrolled on the opt-in rates, so that was
17 also very high.

18 Key takeaways, load reductions for time-of-use
19 rates, on the opt-in side they were in the 10 to 12 percent
20 range. So this is peak period load reductions across the
21 average weekday in the summertime, so 10 to 12 percent peak
22 period. And the peak period in these rates was from 4:00
23 to 7:00 p.m., so fairly narrow peak, and kind of late in the
24 afternoon.

25 On the default side they were in the six to eight

1 percent range. So the average default customer was six to
2 eight percent. Except when you combine, you know, the very
3 high enrollment you get from default with the very low opt-
4 out rates, you know, you get much more aggregate load
5 reduction from default than you get with opt-in, even though
6 the average reduction per customer is lower. So those are
7 kind of key takeaways.

8 Other -- on the critical peak pricing side, so on
9 the average critical peak event day, which my memory is a
10 little fuzzy, I think there were between 9 and 12 event days
11 each of the two summers, the average reductions were in the
12 20 to 25 percent range on the opt-in side, and the 12 to 14
13 percent range on the default side. Those are very
14 substantial reductions, you know, during those critical peak
15 hours on high demand days.

16 The other -- a couple of other takeaways. The
17 impacts persisted across the two summers, so there wasn't a
18 big drop-off, you know, as customers got to know the rates
19 better or what the bill impacts were and things like that.
20 And there was a survey conducted among participants. And
21 the key findings from the survey was that satisfaction rates
22 were very high; 85 to 90 percent of customers on the TOU
23 rates said they were very or somewhat satisfied with the
24 rate they were on. And more customers on the TOU and CPP
25 rates said they felt that the rates were fair, more

1 customers than customers on the standard increasing block
2 rates said they were fair. And almost three times as many
3 customers on the TOU rates said the rates gave them more
4 opportunity to reduce their bills than customers on the
5 otherwise applicable tier.

6 So, you know, those are key findings from the SMUD
7 pilot. And, you know, I'm happy to answer questions about
8 that at a later point. And Scott's going to talk about the
9 new round of pilots that I've also been involved in and the
10 IOUs have been involved in. I can answer questions about
11 that later, too, if any come up.

12 MR. MURTISHAW: All right. So just a little bit
13 of background on the TOU pilots that we have underway for
14 the investor-owned utilities.

15 The Commission passed a decision in 2015, deciding
16 that residential customers of the IOU should be defaulted to
17 TOU rates in 2019. And when you're getting ready to default
18 10 million households to a new rate, you want to make sure
19 that you get it right. So we were very inspired by the work
20 of SMUD. We actually interacted with SMUD staff and with
21 Steve and George quite a bit. And then, as I mentioned
22 earlier, Nexant ended up becoming the consultant to the IOU
23 pilot studies.

24 Now because Assembly Bill 327, which gave us the
25 ability to default to customers the TOU rates, it prohibits

1 defaulting customers to TOU rates before 2018. We could
2 only do opt-in TOU pilots for 2016 and '17.

3 So like the SMUD study, the Commission decided to
4 conduct these opt-in pilots over a two-year period with the
5 same population. That would allow us to examine if there
6 are any changes in load responses between the first and
7 second summers to see if customers either improve load
8 response as they get more familiar with the rate, or if they
9 suffer some customer fatigue and maybe load response drops.

10 So in order to make the results more comparable to
11 what we would expect to see from default rates, the study
12 design actually incorporated a two-stage process. So
13 customers were recruited with a payment to participate in a
14 study, but they weren't told what rate they would be put on.
15 So from that population the IOUs were able to recruit 57,000
16 people across the state of California to participate in the
17 studies. Once you had agreed to participate you were
18 randomly assigned to one of three experimental rates within
19 each IOU territory, or the standard tiered non-TOU rate that
20 you were already on, to serve as a control population.

21 So the new rates went into effect in June 2016.
22 There are a total of nine experimental rates, each utility
23 testing three different rates. And the reason that we did
24 that is we wanted to examine how variations in the number of
25 time periods, there's a hypothesis that customers would

1 understand just peak/off peak more easily than they would
2 understand peak/shoulder/off peak, or something even more
3 complex.

4 We also wanted to test if customers would be more
5 responsive to shorter peak periods rather than longer peak
6 periods, so the four of the rates, four of the nine rates,
7 include three time periods. Three included only two time
8 periods. One includes three time periods with a springtime
9 daytime super off peak to test whether customers can
10 actually increase load during those overgeneration periods.
11 And one rate, one of SDG&E's rates is a dynamic rate.

12 So we have interim results from the summer of
13 2016. They were just published almost exactly a month ago.
14 However, results are not available yet for the dynamic rate,
15 or we don't, because the rates only went into effect in
16 June, we don't have results from that springtime day --
17 weekday super off peak. We'll have those next year.

18 Just to really quickly go over some of the
19 findings, the hypothesis that customers would respond to
20 shorter peak periods more strongly than longer time periods
21 turned out not to be true. Responses were pretty similar.
22 The rates that included a shoulder period showed
23 statistically significant reductions during those shoulder
24 periods. So we know that customers actually can understand
25 more complex TOU rates.

1 Just to give you a sense of the range of
2 reductions across the nine different -- or the eight
3 different rates, they ranged from 2.7 percent reduction for
4 one of the rates in SCE's. That was kind of an outlier.
5 All of the other rates ranged from four percent to about a
6 six percent reduction. And coincidentally enough, for
7 PG&E's rates that were -- the results that we got from the
8 hot climate zone, which would be the area around SMUD, we
9 had nearly identical results to SMUD's default TOU rates,
10 about 6 percent or .11 kilowatts per customer, per
11 household.

12 There were also some small but statistically
13 significant reductions in total usage across almost all
14 rates. Those range from one to three percent in just total
15 reduction, not just shifting load. So just -- I guess I'll
16 give you a sense of what are some of the implications for
17 these findings from the first year of the results.

18 Some of Energy Division staff ran some numbers and
19 looked at the number of households. And if you assumed a 20
20 percent opt-out rate, which was much higher, we had very
21 similar opt-out rates to SMUD, one-and-a-half to two-and-a-
22 half percent, according to the utility. But if you assumed
23 a 20 percent opt-out rate, we could pretty safely expect to
24 get somewhere between 280 to 330 megawatt peak period
25 reduction pretty reliably, though it's not a lot. But keep

1 in mind that this is only for the first year. And we think
2 that as more automated technologies are pushed out and as
3 customers become more familiar with the rates, and as their
4 purchasing decisions are affected, that the longer-term
5 elasticity will be larger than the short-run elasticity.

6 Overall, like SMUD, customers reported
7 satisfaction with the rates. We had very low opt-outs. So
8 I think the results are encouraging. And we'll know more in
9 about a year.

10 One other quick update. We'll be -- because AB
11 327 allows us to default customers in 2018, we're doing
12 another round of pilots on a default basis. And there we're
13 largely testing operational readiness, in addition to any
14 other research questions. So the total number of customers
15 expected to be defaulted in 2018, just for the pilot, are
16 700,000 households. It will allow us to study a lot of
17 different variables with statistical significance.

18 MR. GEORGE: Could I just add one thing to what
19 Scott said?

20 One of the primary goals of these opt-in pilots
21 was to see what demand reductions would be as we push the
22 peak period further into the evening, because that's
23 something we hadn't really studied much as an industry
24 and/or in California. I mean, the SMUD one was 4:00 to
25 7:00, but almost all of the rates in the pilots that Scott

1 talked about have peak periods that go as late as 9 o'clock.
2 The different rates vary; some are 6:00 to 9:00, some were
3 4:00 to 9:00. I think one of them is maybe 4:00 to 8:00 or
4 something like that, it depends on the rate.

5 But the finding of a six percent reduction in the
6 hot climate zones in PG&E's service territory were all
7 rates. Two of them were 4:00 to 9:00 and one was 6:00 to
8 9:00. And I think that's very significant, as I saw the
9 duck curve stuff earlier, you know, with trying to manage
10 the loads in the evening. It was sort of unknown, you know,
11 what will customers do when they come home, because they're
12 home in the evening. In the afternoon you've got a lot of
13 people that are away and it's easier to manage the air
14 conditioning. And the air conditioning drops off in the
15 evenings, as well. So, you know, one of the big finding was
16 that there is meaningful demand reductions with these later
17 peak periods.

18 And we also looked at weekends, because San Diego
19 in particular, sometimes they'll find peaks on the weekends
20 and stuff like that. And we find similar demand reductions
21 on the weekends compared to the weekdays, so that's another
22 key finding.

23 MS. BROWN: Okay. So San Diego Gas & Electric, we
24 had a pilot program that was approved by the California
25 Public Utility Commission in 2016 that authorizes us to

1 install 3,500 charging stations at up to 350 locations for
2 workplace and multi-unit dwellings. What's exciting about
3 it is, as we were talking about all morning long, dropping
4 hydro and wanting to, you know, get load into the grid at
5 the right time, our program is really -- that's what it's
6 really designed for. With that program, we put in a rate
7 that we call the VGI or vehicle grid integrated rate. And
8 what that rate does, it's not just a time-of-use rate, but
9 it actually uses Cal ISO day-ahead signals.

10 We've tested the rate. We've been testing the
11 rate with our employees. We have over 350 employees right
12 now that charge at work. And we definitely have seen when
13 the price is up, that people charge less. I don't have data
14 numbers to share with you, but it's small as far as our
15 population. But the concept of people are going to respond
16 to a price signal, we really believe that that's the way to
17 go.

18 The really good thing is if you think about when
19 people drive EVs, they're going to get up in the morning and
20 if they're car is charged, they're going to come to work.
21 They're going to be able to charge during that time when the
22 renewables are there and we want the load. Then they're
23 going to get home and they're going to be able to charge at
24 super off peak again when the generators are sitting at the
25 bottom. And, you know, we heard some complaints from the

1 generators, and it's really about the flexibility on them;
2 right? We turn them off, turn them on, and they're not
3 designed for that.

4 So if we can, you know, if we can send the right
5 price signals for people to charge at the right time, we're
6 going to really be able to help when we -- as we go to our
7 50 percent renewable goal.

8 MS. DOUGHMAN: Okay. Great. So I wanted to ask
9 the panelists to discuss the biggest barrier that you face
10 in this area.

11 Why don't we start with Linda this time.

12 MS. BROWN: Okay. The biggest barrier? There's a
13 couple barriers. I mean, we believe that probably one of
14 the biggest barriers in transportation electrification is
15 infrastructure right now. You know, people have that, I
16 mean, to be able to get to where I need to be and have the
17 infrastructure, and so that's definitely one barrier.

18 And then the education and outreach, which we're
19 all ramping up our efforts to do. Technology is there on
20 the light-duty side. It's come a long way on the medium-
21 duty and heavy-duty. So as we have these new pilots, we're
22 seeing technology advancing very quickly.

23 MR. MURTISHAW: I think for the PUC and the IOUS
24 the -- there's really just an implementation barrier, which
25 is that the section of code, Public Utilities Code 745,

1 includes a lot of requirements that the PUC has to meet
2 before defaulting customers onto TOU rates. And these
3 include things like evaluating the impacts of households
4 with seniors in hot climate zones, whether TOU rates would
5 cause undue hardship for low-income customers in hot climate
6 zones.

7 So part of the -- one of the intents of the opt-in
8 pilots was to oversample for some types of households so
9 that we could see, are there differences between households
10 with seniors, both in terms of load reduction, but also in
11 terms of satisfaction, or do they report experiencing
12 discomfort on a greater level than households with seniors
13 that remain on the standard tariff, for example. And so
14 we're doing our best to meet those requirements and to tease
15 out of the studies.

16 One of the things that we found is that households
17 with seniors have load responses that are almost identical
18 to households that at least themselves identifies as having
19 seniors. And so it seems that seniors are just as capable
20 of shifting their loads as anyone else.

21 We do see a pretty big difference between the load
22 impacts of CARE customers. This is the rate reduction for
23 low-income customers, California Alternative Rates for
24 Energy. Those customers show smaller load reductions than
25 non-CARE households, and I think that that's largely for two

1 reasons. One, you know, many -- a much larger share of
2 those customers are in smaller housing units, often in
3 multi-unit dwellings, so there's just less load to shift.
4 But also one of the findings is that, especially among very
5 low-income CARE households, there was less understanding of
6 the rates that they had been assigned to. They couldn't
7 correctly name what the peak periods were.

8 So there's -- we're not sure that we understand
9 exactly why some of this is true, but we think that there
10 are probably some issues with English as a second language
11 and presentation of the materials, that could be improved.
12 So one of the things that we'll have to consider is whether
13 to exempt some populations from the default.

14 MR. GEORGE: It's funny, as I've worked in this
15 area for close to 15 years now on time-based pricing around
16 the world, you know, if you'd asked me that question 15
17 years ago, I'd have a very different answer than I have
18 today, certainly in California. It's so funny, when I work
19 in other states, I get lulled into thinking that they're as
20 advanced and they're thinking about things like this, as
21 California is, and most of them are not. And the dearth of
22 data in other states is huge.

23 But, you know, 15 years ago I would have said the
24 lack of empirical data on, you know, on how customers would
25 respond to these, even though, you know, those that have

1 been around as long as I have knew that there were, you
2 know, a dozen studies done in the late '70s and early '80s
3 on time-based pricing, but they were such small samples and
4 things like that, it was hard to know.

5 But, you know, usually now, today, you don't run
6 into questions about whether time-of-use pricing will -- you
7 know, whether customers will respond to time-of-use prices,
8 they will. There's no question. There's been -- any of you
9 that have seen my former colleague, Dr. Faruqui, give his
10 many, many speeches about the, you know, the arc of demand
11 response, or whatever he calls it, the arc of price
12 elasticity, you know, there's a lot of studies out there
13 that say it's no longer a question about whether customers
14 can understand these rates or whether they will respond to
15 them. It's really a lot of things like Scott just
16 mentioned. It's what's the impact on certain customer
17 segments.

18 And that's why in this latest round of pilots, and
19 we'll continue to look at it in the default pilots that are
20 coming up, is looking at that, do I have large enough
21 samples and things like that to develop the empirical base
22 so that you're not fighting myths and hypotheses or people
23 arguing about what their grandmother would or wouldn't do.
24 You know, gather the empirical data to answer those
25 questions and then fight over, once based on fact-based

1 arguments, then decide what you're going to do.

2 So we've come a long way in California, including
3 as to all the regulators and stuff. There's miles to go
4 elsewhere in the country on a lot of this stuff. I'm
5 involved in designing pilots in New York now where they have
6 no AMI meters. But they are now looking at it. I mean,
7 the next generation of pilots, I think, in the industry are
8 going to be about demand rates for residential customers.
9 I'm designing a pilot for ConEd right now, looking at demand
10 rates.

11 And then there's the stuff that's been lurking
12 around that is potentially important for segments of the
13 industry, which is, you know, the kind of prices to devices
14 stuff we've been talking about for a long time, the sort of
15 all-singing, all-dancing rate that has a lot of moving
16 parts. And the working hypothesis is that, you know, you
17 need to wrap technology around rates like that. You've got
18 the hourly pricing. You've got the peak period stuff.
19 You've got maybe demand rates and things like that.

20 And ConEd is also going to implement a pilot,
21 they're calling it their Smart Home Rate Pilot, that will
22 look at a very complex rate. And San Diego has a version of
23 that, as well. They've got -- you know, both of these are
24 going to be pretty small samples.

25 But the night's (phonetic) pilot and the current

1 pilots that we haven't gotten results for yet was San
2 Diego's -- I don't know, I forget what you called it.

3 MS. BROWN: WEN energy.

4 MR. GEORGE: Yeah, WEN energy, or something like,
5 that, their WENN energy rate. And hopefully we'll see, you
6 know, what that looks like in California, and we'll see what
7 it looks like in ConEd where they're, you know, they're
8 reforming the energy vision, things going on and all that
9 kind of stuff. But we're probably a couple years away from
10 knowing too much about those real complex rates.

11 But the demand rates is kind of, I think, the next
12 generation of pilots that will be done in the industry. I
13 don't know if that will happen in California. I know it's
14 happening in New York.

15 MR. DEVINE: For pump storage the single biggest
16 obstacle is the lack of a defined procurement process in
17 place that will allow a project, like Eagle Mountain, to be
18 evaluated on cost effectiveness and, if so, to be developed
19 and constructed and financed. Pump storage was excluded
20 from the PUC's storage mandate, 1,325 megawatts. I think in
21 my discussions with Staff and reading the order, that there
22 was concern that a large project, like Eagle Mountain, which
23 was 1,300 megawatts, could potentially dwarf the ability to
24 incent new technology, and we certainly appreciate that.
25 But the lack of a procurement process means we've been

1 trying to talk with various parties about how to procure a
2 project like Eagle Mountain without success since that order
3 came out.

4 Some of the big complex storage projects that are
5 low cost on a dollar per megawatt hour basis have other
6 obstacles that need to be addressed. And the first,
7 obviously, is one of timing. These projects take about four
8 years to construct and a couple years to engineer to procure
9 the equipment. So in order to have something in place to
10 meet some needs in 2024 or 2025, you need to start a
11 procurement process now or a couple years ago.

12 The second is, again, these projects are large and
13 provide a wide range of system benefits. And procurement
14 processes that kind of deal on one low serving entity after
15 another, sometimes it's -- especially in today's
16 environment, it might be hard for one single entity to
17 procure a whole 1,300 megawatt project, especially one
18 that's providing system benefits in an emergingly
19 competitive retail marketplace. We appreciate that.

20 And finally, there is this whole issue, and we've
21 been working both the ISO and the PUC on -- both in the IRP
22 process and some others about how you value storage. And
23 you look at, again, both the parts of a storage project that
24 can be monetized through, you know, current market pricing,
25 as well as the system benefits, which range from, again, the

1 ability to provide, again, long duration storage, so to deal
2 with some of the negative pricing in that belly of the duck,
3 as well as in some of the ramp issues as we can generate --
4 you know, quickly switch from storing energy to generating
5 energy.

6 And so we think some accurate modeling data will
7 allow us to better evaluate the benefits of large storage
8 and allow the ISO and the Energy Commission and the PUC to
9 make good decisions about how that procurement process might
10 lay out.

11 I think, as we saw from the discussions this
12 morning, some of the issues around the duck curve are coming
13 at us faster than anticipated. And right now is the time
14 for the policy makers in California to look at putting in
15 place a procurement mechanism for pump storage.

16 MR. BULLOCK: All right. So some of the biggest
17 barriers we're seeing for storage adoption and
18 sustainability, one is understanding the value streams and
19 understanding what storage can bring to the grid. Recently
20 I heard kind of an analogy that storage is like the
21 Rorschach test for the grid, where everybody who looks at it
22 sees something different. Somebody sees a load. Somebody
23 sees a generator. One person sees capacity. The other sees
24 frequency regulation or voltage support. So there's a lot
25 of different value streams and a lot of different ways that

1 storage can be used on the grid. Testing those out and
2 proving them and understanding them, I think, is a big
3 barrier.

4 Monetization of these value streams, so, you know,
5 some things like capacity are clearly monetizable. Energy
6 is obviously -- there's ways to monetize that. Right now
7 you can't bid behind-the-meter assets into the CAISO market.
8 Solar ramping, there's no valuation for that. Voltage
9 support obviously adds a clear benefit to the grid, but
10 there's no way to clearly monetize that beyond looking at,
11 you know, metrics of reliability.

12 Stakeholder sharing. When you look particularly
13 on behind-the-meter assets you've got a customer that's
14 getting value from it. You've got the utility that can
15 potentially get value from it. And then you've got third
16 parties, as well. So setting up those contractual
17 structures so that everybody is a winner with storage is a
18 challenge, and aligning those with the utility and everybody
19 on the network.

20 The timeline and planning cycle is another
21 challenge. You know, you know, understanding early on what
22 the needs are on the grid and making sure that the
23 distribution engineers and asset management team really
24 understands storage is an arrow in their quiver that can be
25 used.

1 And then financial certainty. So in a highly
2 uncertain regulatory environment and in a market that isn't
3 sure how storage is going to be used yet, creating bankable
4 solutions that have low cost of financing can be challenging
5 right now, although that's certainly getting a lot better.

6 MS. DOUGHMAN: Okay. So next we'll have Alex
7 Sherman from Advanced Microgrid Solutions. And as you give
8 an overview of your organization, could you also address the
9 biggest recent change or development?

10 MR. SHERMAN: Thank you. Sorry. Thank you
11 everyone for your patience. I apologize for walking in
12 late. Small scheduling issue.

13 My name is Alex Sherman. I am the Director of
14 Solutions Design and Analytics at Advanced Microgrid
15 Solutions. We're a small company that's been around for a
16 couple years. And our goal and our current charge is
17 aggregating behind-the-meter resources and managing those
18 assets and achieving a real scaled distributed resource that
19 we can use to provide grid services, as well as deliver
20 value to the customers that host those assets. I'm not 100
21 percent sure what's been covered so far, so let me approach
22 this from step one.

23 You know, we're able to provide a couple different
24 key services that utilize these demand managements and the
25 demand management of these resources. Demand management,

1 energy efficiency, you can view on the top graph that we've
2 provided for people who are uninitiated to storage.

3 The way that I'd like to view the graph is the
4 gray mountain that you see at the very top of the chart is a
5 customer's load profile, their energy pre battery. So
6 there's some baseload that's present in the evening when
7 plug load, server racks, things that are on doing on the
8 evening. They ramp up in the morning and then shut down
9 once people go home for the evening.

10 And then the blue load that's superimposed over
11 that is what happens after a battery is acting on the load.
12 We're providing demand management during the early morning
13 hours and holding a load to a specific threshold. And then
14 in the afternoon the battery that we've located behind the
15 meter discharges at full capacity. And what the grid sees
16 is a commensurate reduction in load equivalent to what the
17 battery is discharging. So the battery is essentially
18 replacing or displacing, let's call it, electrons from the
19 grid. And that, in turn, on an individual customer, is
20 aggregated and metered at scale.

21 So the graph below are sites that we actually have
22 in the ground right now, operating as part of a 90 megawatt,
23 260-megawatt hour resource that we're building in
24 California. And our optimization engine is able to optimize
25 the use of all of these assets in conjunction with each

1 other to provide real services to the grid. And the two
2 charts and the black chart on the bottom right, you'll see
3 at the very top, four stacked load profiles for individual
4 customers, each with a battery acting on it. And then on
5 the bottom is the metered load output from the batteries
6 itself. So not only are we showing load reduction services
7 for the grid but, again metered empirical output that we're
8 able to prove and demonstrate in terms of what we're able to
9 displace. And in large form, that's the goal.

10 I mean, I guess I'll dovetail this into an answer
11 to the question of what's the biggest recent change. You
12 know, our ideas of five years ago, aggregated DERs, no one
13 really thought would be an asset, particularly because of,
14 let's call it the visibility issue and the demonstration of
15 performance. You know, we can pull up several examples.
16 Demand response is one of them, which is an aggregated
17 resource and has been for a while. But demonstrating
18 performance across that relies on baselines, and it's much
19 more difficult to verify.

20 So the biggest change for us that we see is that,
21 you know, the cost of these system, and in particular the
22 ability to locate them behind the meter and then meter them,
23 we can demonstrate a lot of value, both to the customers and
24 to the grid at large.

25 MS. DOUGHMAN: Great. Do you also want to talk a

1 little bit about some of the barriers?

2 MR. SHERMAN: Yeah. Actually, if we can flip to
3 my next slide, that will be a good precursor to this.

4 So I don't know how many of you are familiar with
5 this chart. This is from a Rocky Mountain Institute study
6 called the Economics of Battery Energy Storage. And it
7 essentially, it's trying to demonstrate all the different
8 values that energy storage could provide, both to the
9 transmission section, let's call it, of the grid, the
10 distribution section, and behind the meter to customers in
11 general.

12 But the primary takeaway to this, to answer the
13 question of barriers is that, you know, energy storage is
14 still an expensive technology, and an expensive technology
15 to deploy and to manage in its current state. And it relies
16 on multiple revenue streams to be able to support the
17 deployment of these systems.

18 We now have the technology. And AMS is working to
19 demonstrate that multiple different services can be
20 supported by an individual battery system, but also by an
21 aggregated fleet of batteries. But at the same time, we
22 need to address some of the barriers that currently exist to
23 tapping into multiple different revenue streams, whether
24 that's wholesale market revenue streams while performing
25 behind-the-meter energy savings for the customer,

1 participating in multiple different capacity programs,
2 valuing the systems and what they're providing.

3 If they're going to be assisting in participation
4 of existing programs, for instance to bring the demand
5 response example again, demand response programs are
6 currently valued with an expectation of trying to hedge
7 against certain things like customer fatigue. And, you
8 know, acknowledging that resources aren't necessarily as
9 firm as we'd like them to be. But if you were to
10 participate in a demand response program with a battery,
11 you'd be able to eliminate some of those issues. And then
12 the question is should that be valued differently? Even
13 though it could be currently -- the two can participate in
14 the same program, our question is really just, you know, if
15 -- separating energy storage out and classifying it with a
16 new set of rules.

17 MS. DOUGHMAN: So I'd like to go around with one
18 last question, and then turn it over to the dais.

19 So what action is needed to address the barriers
20 that you've raised?

21 MR. SHERMAN: I think the first is, for us,
22 ensuring that the SCHIP Rules encourage standalone storage
23 resources. And that's because at this point, you know, we
24 at AMS at least can see a future where there are enough
25 market opportunities, enough different market opportunities

1 and revenue opportunities, let's call them, to support and
2 to finance the deployment of these systems at large. But
3 they're still emerging as we start to see and to demonstrate
4 how we can use these in multiple ways, these systems in
5 multiple ways.

6 So we see SCHIP as a critical bridge until the
7 market is able to catch up. And, you know, we can make
8 arguments about why pairing storage with other systems is
9 more or less valuable. But standalone storage in and of
10 itself, we think demonstrates enough value to merit rules
11 that encourage standalone systems.

12 In addition to that, you know, I think the two
13 bigger things are settlement rules that are right for proxy
14 demand resources in the wholesale market, again changing
15 regulations to allow participation in multiple different
16 revenue streams.

17 And then finally, market signals, clear, stable
18 market signals for storage. And that can be, you know,
19 anything from clarifying developing market rules for
20 wholesale markets, or also, you know, changing or modifying
21 demand response values so that it values and recognizes the
22 full value of storage and the full potential of storage.

23 MR. BULLOCK: So I think you mentioned several
24 that I would also echo. I'll try to add to it and not
25 repeat the ones.

1 So first of all, I think continuing, you know,
2 policies, such as SCHIP, and things like EPIC pilot projects
3 and things that promote storage are critical for the
4 industry to prove out and to evaluate what the benefits
5 might be. I think that's -- you know, measurement
6 verification of these systems is key so that long-term
7 planners can start adding it to the toolbox, so they can
8 start looking at things that are going to support the grid
9 from a locational perspective, time-of-use perspective, and
10 across the grid.

11 Creating carveouts in some of these policies so
12 that behind-the-meter storage can also be an economical or
13 proved out as an economical benefit, rather than just, you
14 know, kind of large-scale in-front-of-the-meter projects.
15 And then creating policies that make sure that there's
16 financial stability over the long term. You know, 10-year,
17 20-year horizons are common in solar, not as common in
18 batteries. But creating that so that private finance will
19 be attracted to it is key, as well.

20 MR. DEVINE: Some specific issues around long
21 duration storage that might separate from some of the
22 previous comments.

23 Again, as I mentioned earlier, as a part of the
24 state's policy to develop a procurement pathway for pump
25 storage so that it can be considered, I think as we heard in

1 testimony earlier today, as we -- given the issues around
2 overgeneration that occurring this spring, we look out to,
3 as we achieve -- try and achieve the state's greenhouse gas
4 reduction goals, I think those issues become more serious as
5 we -- at the middle part of the next decade. And for long
6 duration storage projects that have kind of a longer
7 incubation period, we need to put some policies in place
8 now.

9 I think we also heard from Mark Rothleder this
10 morning that the ISO is completing some re-studies regarding
11 the value of bulk storage. And we look forward to seeing
12 both of those come out later this summer, as well as kind of
13 the first set of model portfolios coming out of the IRP
14 process.

15 But this financing mechanism is very important.
16 These projects, if we look at kind of the history of Helms
17 and other projects like that around the country, are very
18 cost effective. They have a large upfront capital cost, but
19 provide long-term -- provide benefits over a long period of
20 time, both that can be recovered through market mechanisms
21 and through other societal benefits. And we would like to
22 see those wide range of benefits examined.

23 I think that's the -- again, we agree that to meet
24 the state's aggressive goals, we really need to kind of be
25 looking at all of the above, including the demand response

1 and flexible generation in both short and long duration
2 storage.

3 Thank you.

4 MR. GEORGE: Again, my answer to this question
5 would be so different everywhere else but in California,
6 because you have overcome a lot of the barriers. And I
7 would say the first barrier to time-based pricing was
8 getting the meters in place, so you got that taken care of.

9 You know, a barrier to putting in default pricing,
10 if you think that's a proper policy, which, you know, was
11 two things, one is an empirical measurement of what -- how
12 people would respond to default pricing. So SMUD kind of
13 put the first stake in the ground on that and provided very
14 useful information. And now the IOUs, at the direction of
15 the Commission, are, you know, moving forward with some
16 default pilots to better understand that from a couple of
17 different perspectives.

18 You know, getting the legislative barrier to
19 default pricing out of the way, you checked that box.
20 That's happening, you know, in nine months or so, 2018.
21 And, you know, I'm an empiricist. So my answer to every
22 problem is, you know, study it, measure it, have fact-based
23 policy decisions.

24 And California is really working on that. I mean,
25 the implementation of the opt-in pilots as a precursor to

1 doing the default pilots, as a precursor to most likely
2 doing default pricing was all key steps to eliminating
3 barriers, to developing information that answers the
4 questions, well, what's the impact on low-income customers?

5 What's the impact on seniors? What kind of demand response
6 are we going to get? All of those things are very, very
7 important to making sound pricing strategy policy decisions.
8 And you guys are going about this in a very methodical way,
9 and I think that's the way it should be done.

10 I think something I would say, keep in mind, as
11 you finalize the decisions and stuff like that, there are --
12 there's a large school of thought that the solution to every
13 problem with time-based pricing, whether it's bill
14 volatility in the summertime or impacts on low-income
15 consumers or whatever has dumbed down the price signal so
16 that those things are smaller, so that you don't get as much
17 bill volatility or you don't get as much impact on certain
18 segments and stuff like that.

19 And I just would urge the Commissions and the
20 policymakers to kind of keep an open mind about that.
21 That's not the only solution to some of these problems. You
22 know, a solution to bill volatility over the seasons, we
23 have a lot of bill volatility in California, either -- under
24 the increasing block chairs (phonetic) and, you know, those
25 increasing blocks are getting diminished. But, boy, when

1 there was a five chair increase in block rate, man, the
2 summer bills went up like crazy in Bakersfield and stuff
3 like that. So there's a lot of variation over the seasons.
4 And the utilities have implemented programs, like balance
5 payment plans, that kind of address that. I mean, those
6 same kinds of things can be addressed -- can be used to
7 better manage the bill volatility across seasons with time-
8 of-use rates.

9 Now the question that raises is whether that dumbs
10 down the price signal, it hides the price signals to
11 consumers, whether you're on a balanced payment plan or
12 whether your demand reductions will be lower? And I kind of
13 pushed really hard. I worked on the design of the upcoming
14 default pilots. I pushed really hard to get that as test
15 treatment in these default pilots so we can answer that
16 question: How much does it impact the price signal to
17 consumers, and how much does it, you know, eliminate the
18 demand reduction that you'd get if you didn't provide that
19 balanced payment plan?

20 And then the other, you know, kind of, I think,
21 barrier, and Scott mentioned some of the findings from the
22 interim evaluation was that certain groups didn't have a
23 very good understanding of what the peak period was, and
24 very much about the rates. We did these surveys that sort
25 of, you know, tested their rate knowledge. And we found

1 that it varied across, you know, CARE versus non-CARE groups
2 and low-income groups and stuff like that.

3 So one of the things we're really focusing a lot
4 of attention on in the upcoming default pilots is education
5 and outreach. And we developed, across the three utilities,
6 a lot of test cells about the kind of information to provide
7 to customers so that they both understand what the bill
8 impacts might be if they stay on these rates, that we test
9 different communication channels and different kinds of
10 information treatments to help customers better understand
11 how to manage their bills under a different kind of price
12 signal.

13 And so those tests -- and the beauty of those
14 tests is a lot of them will -- you'll get information on
15 them fairly quickly. You know, if we see -- we'll be
16 looking at awareness levels and opt-out rates in the default
17 pilots as a function of the kind and quantity of structured
18 bill information that will be provided to customers as part
19 of the default process, and other kinds of information
20 treatments and stuff like that. And you'll get information
21 on that quickly. You don't have to wait a year-and-a-half
22 to get -- you know, vote impact measurements and stuff like
23 that. Tests of opt-in or opt-out, you can -- you'll know in
24 six or eight weeks what the answer to those things are. And
25 we'll be using a lot of different test cells to sort of try

1 to hone the education and outreach part of default
2 notification so that they can do a better job and actually
3 roll those things out.

4 So again it's -- you know, the barriers are, you
5 know, California has done better than anyplace in the
6 nation, as far as I'm concerned, in the pricing area in
7 terms of checking the boxes on these things, getting the
8 empirical data. And you're continuing to do that, to make,
9 you know, sound long-term pricing strategy decisions. So
10 kudos.

11 There's more work to do. A lot of it's already
12 planned and is going to be implemented. So just keep on
13 keeping on and breaking these things down, and keeping an
14 open mind about solutions that aren't just dumb down the
15 pricing as the solution to every problem around differential
16 impacts on customers or bill volatility across seasons and
17 stuff like. Keep an open mind on how you solve those
18 problems without distorting the cost causation and price
19 signaling that TOU rates are all about.

20 MR. MURTISHAW: All right. Well, Steve, who not
21 that long ago said he wasn't going to steal my thunder,
22 pretty much just completely stole my thunder. Pretty much
23 my entire weather event is just gone, it's missing. So
24 rather than answer the question directly, I'm just going to
25 answer it pretty orthogonally, really not answer the

1 question and just raise a few other interesting points that
2 I thought you might find noteworthy.

3 So one, I think there's a lot of hope that
4 automation of response will result in a much larger price
5 response than customers just having to remember these time
6 periods and go around and manually adjust their usage. And
7 Edison, for one its experimental rates, worked with Nest to
8 recruit a subset of customers that already owned Nest
9 thermostats, and then oversampled those customers and tried
10 to see if there was a significant difference in load
11 response. And the answer was there was really no difference
12 in the load response at all, no measurable difference at all
13 in the load response.

14 So Edison and Nest are going to try to reach out
15 to those customers again this year and try to more
16 aggressively push out an automated response or give those
17 customers some suggestions about how to take advantage of
18 their rates to see if they can get a larger response this
19 year.

20 Another is that I think President Picker and I and
21 a lot of the staff at the PUC really hope that whatever
22 basic TOU rate we might choose as a default should really be
23 considered a gateway drug to upselling customers to more
24 sophisticated rates. And one of the reasons I say that
25 really should be the endgame, is that if you look at the

1 SMUD results the default TOU customers reduced their usage
2 six percent. That's not bad. That's pretty good. But the
3 opt-in CPP customers reduced their usage 20 to 25 percent on
4 CPP days when we most need that reduction.

5 So I think that as we're defaulting customers to
6 TOU, we also need to be, you know, we, really, at the PUC
7 need to be looking at ways to encourage the utilities and
8 the customers to opt up, as well, beyond just the basic TOU.

9 One other thing I didn't mention is that a
10 potential challenge to implementing TOU rates is the
11 presence and the accelerating uptake of community choice
12 aggregation. We don't regulate their rates. So their
13 participation in TOU is strictly voluntary. For MCE and
14 Sonoma Clean Power, because they're the most established
15 CCAs at this point, they have volunteered to participate in
16 the pilots. They will -- you know, their customers and PG&E
17 customers will both receive information.

18 Lancaster, because they're still relatively new
19 and getting their footing, chose not to participate. I
20 think over time, they're going to want to generally match
21 whatever the default rate of the incumbent utility is, and
22 so I don't think it's going to be a problem. But it is,
23 like we noted earlier on the planning side, it will
24 complicate coordination a little bit. But I think that
25 they're motivated to participate.

1 And then just -- I thought I would respond to
2 something that Mark Rothleder said at the beginning of the
3 day about the TOU periods that we have. It is true, they're
4 pretty out of date. They don't reflect current conditions,
5 by and large. In the next week or two, we should be issuing
6 a proposed decision for San Diego's GRC Phase 2. You know,
7 I can't disclose too much about that but, you know, there
8 will be some change, there will be some movement. And we
9 have decisions -- or we have proceedings in the works for
10 PG&E and Edison, as well, that hopefully by the end of the
11 year we'll have decisions out that will bring those time
12 periods up to date to reflect current conditions.

13 MS. BROWN: Okay. So what actions are needed
14 around transportation electrification?

15 I want to start by saying that, you know,
16 definitely the CPUC has launched the most aggressive program
17 in the nation, so we're on the right track there. We
18 definitely need to continue to explore the pilots and
19 programs that have already been authorized and the new ones
20 that are on the horizon.

21 Another key element to transportation
22 electrification is that we continue to work with the
23 electric vehicle service providers, the ones that are
24 actually designing and building the charging stations,
25 because we talk about automation, it aligns with the

1 customer experience. And if we think that our customers are
2 really going to understand a day-ahead rate or want to
3 understand a day-ahead rate from the CAISO, they're not.
4 But what they will understand is their bill impact. And if
5 we can make the IT solutions a set and forget, for example,
6 on my app right now, I have my app, when I get to work, I
7 don't charge if it's more than \$.22 a kilowatt hour during
8 the summer, because I know that I can go home and charge for
9 that same price rate. So it's super easy. I go in once, I
10 set my app. And so we've got to continue to work with the
11 people that are making these charging stations.

12 And IT and billing are also -- when we were
13 talking about barriers, we really didn't talk about that.
14 But that's another thing where, you know, they're catching
15 up with us. We're a little bit ahead of them right now.

16 The other thing that, you know, as we listened to
17 the ISO this morning, I think one of the things that the
18 CEC, the ISO and all of the IOUs and the CPUC, we really
19 need to work together as we're gathering all this data to
20 define what these ratepayer benefits are, because we're all
21 proposing programs. But in the end, right, especially from
22 the IOUs perspective, we have to -- we're seeing that we
23 need it. But we need to really put some dollars around that
24 as we go and we try to get these programs approved.

25 And then lastly, we've all talked about education

1 and outreach. And we've got to continue to, you know, keep
2 working with our customers and design programs that work for
3 them.

4 MS. DOUGHMAN: Thank you. I'd like to turn it
5 over to the dais.

6 CHAIR WEISENMILLER: Great. I'd like to thank
7 everyone for being here. Starting with a couple of
8 questions to kick things off.

9 One of them is following up on this conversation,
10 I know there was a CFEE conference a couple years ago where
11 we actually had the OEMs there, and we had the utilities.
12 And, of course, the OEMs were sort of helping, you know,
13 looking at how do they sell these things; right? And, you
14 know, basically people were saying, well, you just have to
15 start explaining to customers about demand charges and all
16 their options and how they can really control it. They were
17 like, no, you know, we want to push that out to -- you know,
18 we need to push those cars out in five minutes. And it was
19 pretty clear, we need someone to step in because -- you
20 know, and just say, okay, how do you make it easy for
21 customers, you know, that they don't really want to try to
22 figure out what's going to happen to the SDG&E and demand
23 charges or know.

24 You know, somehow or another we've got to set that
25 up, be it an app, be it an entity, or something so that, you

1 know, A, the dealership doesn't have to explain all about
2 your rate structure and how it's going to change, and how
3 charging at, you know, right at the neck of the duck is
4 going to be expensive as opposed to, you know, midday or
5 whatever. So how do they do that?

6 MS. BROWN: Well, I don't know if we're ever going
7 to get an average customer to understand what a duck curve
8 is; right?

9 CHAIR WEISENMILLER: Right.

10 MS. BROWN: We're in this industry. And there's
11 probably people in this room that, you know, just recently
12 learned it, or soon.

13 CHAIR WEISENMILLER: Yeah.

14 MS. BROWN: But I think if we can make the app
15 simple enough, to a customer it's about, in the end, what
16 the bill impact is, right --

17 COMMISSIONER RANDOLPH: Right.

18 MS. BROWN: -- to them. And so if we can get them
19 to go on a grid integrated rate, and if there is, for
20 example, even with time of use, whether it's a time-of-use
21 rate or, you know, SDG&E's proposed dynamic rates, if you
22 change your pool pump, especially during the winter, to the
23 evening hours, instead of doing it when you normally did
24 during the day, you're going to see a positive impact on
25 your bill. And so we've just go to continue to explain

1 that.

2 And the car technology, the OEMs are finally -- I
3 mean, right, you go into the dealers now and you have
4 choices, whereas before you really didn't have choices. So
5 the cars are getting really smart. So it's not only the
6 app, but you can also do -- you know, some of the cars, you
7 can set it in your car, too.

8 CHAIR WEISENMILLER: What about -- do you -- you
9 know, SDG&E has a fairly good workplace charging
10 environment. What are you doing on like vehicle-to-grid,
11 you know, one way or two way; right? You seem to -- we were
12 trying to push that. You know, we've done the L.A. Air
13 Force Base after a pretty painful process. We're now
14 looking at Miramar. But, you know, we need to get more
15 experiments in that area. It would seem like the utility
16 workplace environment, you know, would be the next logical
17 step.

18 MS. BROWN: We agree.

19 CHAIR WEISENMILLER: Okay. Move.

20 MS. BROWN: Yes.

21 CHAIR WEISENMILLER: Okay. Proceed.

22 On time of use, first, I want to thank both of you
23 for being here. We got a little bit nervous where SDG&E --
24 you know, basically, the Energy Division wasn't quite
25 prepared to talk today. And I guess SMUD is developing its

1 proposal. And we just did not want the gap.

2 So having said that, you know, and now having both
3 of you here, I guess one of the things I want to talk about
4 is the customer acceptance part. I know this is one of the
5 things President Picker, you know, really thought SMUD did
6 well and is really trying to figure out what the PUC can do
7 as it's designing and rolling us out to encourage that type
8 of customer orientation at the utilities.

9 And I was going to obviously encourage both of you
10 to chat a little bit about that part of it, you know, not
11 just the -- not just the theory, but how do we actually get
12 people comfortable in, you know, being able to look at their
13 opportunities here?

14 MR. MURTISHAW: Well, and I'll say that is a focus
15 of President Picker's, and he has some background in
16 campaigning social marketing when he was the chief of staff
17 to the former mayor of Sacramento. Working with the
18 communities, he thought very hard about how things are
19 messaged to people. And largely at his insistence, the
20 Energy Division worked with the utilities to do these focus
21 groups and design thinking sessions with average customers
22 and to get a sense of what messages resonated the most, how
23 could you communicate some fairly complex concepts in an
24 easy manner that was easy to digest and retain. And that's
25 informing our work on designing the pilots.

1 I mean, overall I think we're finding that
2 customer satisfaction is pretty high. There were some
3 subgroups that showed some statistically significant but
4 small differences in that they were less satisfied with the
5 utility or less satisfied with their service when they
6 participated on the TOU rates, but those were pretty small.
7 So no major backlash yet that we're seeing in the results.

8 I think it's just -- it's a learning process in
9 terms of continuing to work with customers year after year
10 to make sure that as many of them as possible really
11 understand and act on the rates. But some of the
12 demographic and psychographic segmentation analysis that's
13 been done, both for the investor-owned utilities here and
14 other markets, will show that pretty consistently there's a
15 20 to 30 percent portion of the population that does not
16 respond, does not care, will not respond. And so you also
17 need to know when to cut your losses and who to focus on.
18 And that's what we're, in part, what we're trying to learn
19 here. Some people who will just jump on this, 10 to 15
20 percent of early adopters, people in the middle, who with
21 extra effort and extra education could maybe produce a
22 larger response, but then not waste a lot of our effort on
23 people who just, you know, don't care or they -- the bill
24 shows up, and as long as it's a tolerable bill, that's all
25 they need to know.

1 MR. GEORGE: Yeah. I agree with everything Scott
2 said, and I'll add a few things.

3 I mean, I think as I outlined in the -- you know,
4 the opt-in pilots that are in the field right now and got
5 the first evaluation out, we didn't -- we decided not to
6 spend a lot of time testing different education and
7 outreach. It was more important to understand the different
8 rates and what the impacts would be with the different rates
9 and stuff like that.

10 With the default pilots, I think there's a belief,
11 and I agree with it, that, you know, there's a couple things
12 you've got to do well if you're going to default the entire
13 residential population on a time-of-use rates. One is
14 understand how to make almost everyone aware. You know,
15 there is diminishing returns and everything. But, I mean,
16 you know, we found in the SMUD pilot that, don't quote me, I
17 think it was 20 percent or so of customers when we did the
18 survey there weren't aware that the rate had changed. And
19 another 20 percent weren't aware that they could opt out.
20 So, you know, that's in part why the enrollment was so high.
21 But we still got, you know, very meaningful demand
22 reductions. And, you know, as I said, the low opt-out
23 rate -- or the high -- yeah, the low -- the high retention
24 rate combined with the lower average demand reduction still
25 gave much larger aggregate reductions than for an opt-in

1 program, even a very successful opt-in program, like SMUD's
2 was.

3 But in -- so in the default pilots that are coming
4 up we're testing, as I said, a lot of different education
5 and outreach options, both around awareness, so, you know,
6 notification and awareness, and measuring awareness and
7 making sure that -- you know, testing whether you can get
8 high awareness through, you know, a combination of direct
9 mail and email, which is going to be cheaper than all direct
10 mail and stuff like that.

11 So there's no only understanding how awareness
12 varies with different kinds of channel strategies and
13 information strategies but, you know, looking at the cost of
14 those different things, too, because there's dramatic
15 differences in the cost of direct mail versus email and bill
16 inserts and stuff like that.

17 So all of that is going to be studied in the next
18 round, you know, with the several hundreds of thousands of
19 customers that are going to be in those tests. So, you
20 know, that's going to give you a lot of power in your
21 statistical measurements and stuff like that.

22 But then you also want to -- there will be
23 treatments around ongoing education, so it doesn't stop once
24 they're enrolled.

25 So there's kind of three stages with default. One

1 is the notification, the information you provide to make
2 customers aware of what's happening so that they will make a
3 proactive choice of whether they want to enroll or not.

4 Then there's the information you give them when
5 they kind of are enrolled on the rate, the welcome packages
6 or whatever, and what's the content of that? What should
7 that look like? What's most effective?

8 And then there's the kind of ongoing education and
9 outreach, whether that's, you know, seasonal notifications
10 about, well, the rates changing. You know, summer's coming
11 up, the rates going to be changed, and that kind of thing,
12 ongoing education through usage alerts. San Diego has a
13 very active usage alert program where they're providing
14 weekly bill alerts and stuff like that. So there's a lot of
15 different kinds of things you can do on an ongoing basis.

16 And again, the goal is to sort of look at -- you
17 know, to get enough empirical measurements to sort of say
18 what's a cost-effective package of maximizing awareness
19 during the notification process and educating enough
20 customers that you get meaningful demand response and
21 customer satisfaction is high, but without going so crazy
22 that, you know, you're trying to get all these complacent
23 customers that, no matter what you tell them, are not going
24 to do anything because it's just not worth it to them? You
25 know, there are diminishing returns in this sort of thing.

1 So I think, you know, the IOUs, through the next
2 series of pilots -- and the great thing about this kind of
3 stuff is that it doesn't have to be done through pilots.
4 This is the kind of thing, it is a continuous learning,
5 adaptive design, test and learning, whatever your strategy
6 is, you know, as default actually occurs, those kinds of
7 things you can continue to evolve to test, even during the
8 launch program and stuff like that. So I've kind of been
9 encouraging the utilities to keep that in mind, too, that,
10 you know, this stuff doesn't end when the pilot's over and
11 you do default. It should be a continuous learning kind of
12 a thing over time.

13 CHAIR WEISENMILLER: I guess, Doug, the two
14 questions are, obviously, the thing we're struggling with in
15 part on pump storage, regardless of the study, you know, I
16 mean, bottom line is you're not going to project finance
17 based upon anyone's study. It's got to be a contract behind
18 it. It just won't happen. You know, I know the banks just
19 don't believe the studies that well, so you're not going to
20 emerge in pump storage product, period.

21 Now having said that, you need a PPA. And at this
22 point with the CCAs, it's very, very, very hard to get any
23 of the IOUs to sign a contract, a long-term contract for
24 anything, you know? So again we're back to, you know, how
25 do we get past that?

1 The other thing I'd point to, in comparing
2 California and Germany, so Germany has about three percent
3 hydro, which they include all that as part of their
4 renewable package. And a lot of that hydro is pumped
5 storage. And that's on their list of endangered assets
6 because to the extent their wholesale prices are roughly
7 zero off peak and roughly zero on peak, you know, you can't
8 make money off of that with a 30 percent loss. So they're
9 really in the, you know, list of -- they like pump storage,
10 but it's just like they're not sure how to keep it alive.

11 So again, how do we break through this -- you
12 know, you're talking about if the PUC will include it in a
13 procurement or something. But honestly, they won't sign the
14 contracts --

15 MR. DEVINE: Well, I think --

16 CHAIR WEISENMILLER: -- until we deal with the
17 broader issues.

18 MR. DEVINE: Right. No. I mean, I think those
19 are clearly, you know, issues that need to be addressed.
20 Certainly recently, you know, FERC issued a NOPR around
21 store as potentially some portion of it being recovered as,
22 you know, it provides both a generation service, and perhaps
23 a transmission service, so some part of rate recovery
24 through, you know, through -- as a transmission asset, some
25 part through some market rates. How you do that is

1 something that I think is looking for our state to take
2 leadership on.

3 So that's the message that I've kind of gotten.
4 Obviously, we need kind of a new FERC to kind of bless that.
5 But our discussions, and certainly kind of their decision on
6 that NOPR, comments on that seem to indicate that, you know,
7 there is a possibility there for a way to recover the costs
8 across, again, across a broader base of customers,
9 recognizing it provides some level of -- it is a system-wide
10 asset. I mean, we certainly agree that, you know, the
11 large -- the IOUs are concerned about any one of them
12 procuring an asset this large in today's environment.

13 CHAIR WEISENMILLER: I think I'll certainly query
14 both of you on a basic question.

15 Obviously, one of the things that we're also
16 trying to get to is Demand Response 2.0. And certainly, you
17 know, that's been a key part of AMS. But again, all the
18 stuff behind the meter, you know, how do we really empower
19 that, you know, through aggregation to really bring the
20 customers forward? Obviously, the hope is with pricing
21 signals, you know, better pricing signals, we can really
22 help motivate that. But presumably, you two provide the
23 tools, given the right pricing signals where people start
24 responding. So what do we need to do there?

25 MR. SHERMAN: That's a great question. One could

1 almost call it an existential one.

2 So just to repeat, you know, we're trying to
3 figure Demand Response 2.0, what does that look like? And
4 in particular, what does it look like when a customer has
5 full awareness of all the pricing signals that they need,
6 and also maybe one or two assets that sit behind the meter.

7 To be honest, and I'll just say what the current
8 solution is right now is to act on the customer's behalf as
9 the customer expert. I mean, I think, in particular, when
10 you start onboarding complicated tariffs, some of the stuff
11 that we're working with in Edison, you need to have someone
12 whose day-to-day is spent looking at these tariff rates to
13 understand where and how to optimize around it.

14 And, you know, what AMS is trying to do, in
15 addition to just managing the assets, is to build into our
16 asset management platform the intelligence to operate those
17 assets optimally within the tariff structures, however
18 they're set. And in many ways that's part of the pitch for
19 energy storage, is that if it's managed correctly it's a
20 hedge against any tariff change because it's always a
21 question of what you would have paid for electricity versus
22 what you would have paid -- without a battery or without
23 optimized management of your assets -- versus what you're
24 paying for it with. And that's our essential value
25 proposition to customers.

1 Insofar as how we get to Demand Response 2.0, I
2 mean, I do think, much like with Demand Response 1.0,
3 there's a large question, even with your most comprehensive
4 and intelligent commercial customers, with someone who's
5 paid to pay attention to the bills, just how much economic
6 incentive you can provide through pricing signals to get
7 them to change their behavior. At the end of the day, you
8 know, I can't tell a concrete manufacturer that you need to
9 change your shift schedule in order to optimize your energy
10 use because I, as an energy intelligence person, don't fully
11 understand, you know, how they pay their workers, and what
12 the salary and overtime benefits are.

13 Excuse me.

14 And so ultimately, you know, transparency is a big
15 one, transparency so that it's easier for an energy services
16 provider to explain how an optimized energy use can get
17 around some of these -- get around some of these tariff
18 complexities, I guess would be one way.

19 But, you know, I think another way is, and this is
20 going to sound a little selfish, but encouraging the further
21 deployment of energy storage and behind-the-meter assets.
22 Because you have -- I mean, these are already systems that
23 most customers are not going to be able to want to invest a
24 significant amount of resources to deploy on their own.
25 They will want to partner with an energy services company of

1 an asset management company, or a battery provider.

2 But again, you know, the value of doing that and
3 the ability of a battery provider or an asset management
4 company to work with the customer to deploy those is the
5 ability for the asset management to say we can put a system
6 here. We can place one behind your meter. We can enroll
7 the other assets that you've decided to install already on
8 your own hook and we can optimize how all that's used, but
9 we can do it in a way that gives you enough of a savings or
10 a cushion or a hedge against tariff risk to enable you to
11 feel comfortable hosting a system like this, to enable
12 turning, you know, in layman's terms, the keys to your
13 building over to someone to operate as a third party. And
14 then lastly, you know, on top of that, enough to reasonably
15 make an energy services company want to try to pursue that
16 on behalf of the customer.

17 And I think all that taken together, for many
18 customers, it actually represents a good deal, in
19 particular, when we're talking about how this type of stuff
20 impacts them. And by that I mean if I'm an energy manager
21 for a facility and I feel that someone is truly optimizing
22 how all these assets behind the meter are functioning, it's
23 all metered, it's all empirical, and there's a demonstrated
24 way, and it could even be third party verified because the
25 data is all there to show what the savings are, it's going

1 to be much easier for a customer to say this is fine. I'm
2 going to continue to do what I need to do. I don't have to
3 change my shift schedule. I don't have to, you know, send
4 people home an hour earlier just to dodge a time-of-use
5 rate. We're going to do -- you know, we'll do us and in the
6 background, all this is going to be operated for us.

7 MR. BULLOCK: Thank you. I think I dodged having
8 to answer the initial part of the question.

9 I think what I would add to it is maybe, if we get
10 beyond Demand Response 2.0 and we start looking at DR 3.0,
11 and maybe I'm getting a little ahead of myself with, you
12 know, Jetsons and flying cars, but I think where the next
13 step is, is not just optimizing one behind-the-meter
14 customer, but optimizing a fleet of behind-the-meter
15 customers in targeted areas on a feeder or on the network.
16 And that really gets into integrating with the utility DMS
17 and looking at matching up supply and demand so that you can
18 really optimize everything on the network, and not just one
19 customer.

20 CHAIR WEISENMILLER: I was going to thank AMS. In
21 the Aliso context, I think I've spanned half of Southern
22 California to do something, and they seem to be the only
23 ones moving, so I appreciate that.

24 COMMISSIONER MCALLISTER: Yeah. So, you know, I
25 would have asked some similar questions to the Chair, so

1 thanks for those answers.

2 You know, your examples of this, you know, I'll
3 start and kind of go a different direction, but examples of
4 this huge innovation that's going out there, and I really
5 admire what you're doing and I think it's a big piece of the
6 future.

7 I guess maybe you could expand a little bit on the
8 sort of final point you just made which is, you know, as
9 long as it's customer service and it's managing demand
10 charges and understanding complex tariffs and optimizing the
11 operation of a facility, a commercial building, whatever it
12 is, that's all good and that needs to be done, and there's a
13 lot of benefit in that.

14 How do we -- and you mentioned before, Alex, the
15 need for multiple revenue streams. And, you know, how do we
16 create reliable and relatively low transaction cost revenue
17 streams from the grid across the meter to the building, you
18 know, so that you could participate more readily in demand
19 response and sort of, you know, really do that in a way that
20 isn't a hassle and makes it beneficial for the grid, and so
21 that we can actually use our buildings as the, you know,
22 shock absorbers of the system with all the renewables
23 sloshing around? You know, do you have sort of some ideas
24 about how that would look if it were done well?

25 MR. SHERMAN: Yeah, this is what I dream about at

1 night if it's a good night.

2 COMMISSIONER MCALLISTER: Me too.

3 MR. SHERMAN: It's a good question, and I don't
4 mean it in a patronizing way. And to suggest that I've got
5 solutions is to also suggest that I do not fundamentally
6 understand how these types of rules are made. I would say
7 that if there's a general structure to it, it's just that we
8 need to be able to understand the, let's call it a holistic
9 impact of any particular rules that are designed.

10 As an example, if I'm trying to install a battery
11 at a customer site and my proposal is that we're going to
12 reduce their demand charges, and in exchange for hosting the
13 battery site and reducing the demand charges, you know,
14 we're also building extra hours of capacity to be able to
15 bid that into -- or to satisfy a contractual obligation with
16 Southern California Edison, that's what we're currently
17 doing.

18 And right now our optimization engine, the thing
19 that drives the batteries, is trying to predict on a daily
20 basis how much we can discharge from the battery for load
21 management in order to, A, preserve enough capacity to
22 reserve for Southern California Edison. When they request
23 that capacity, we need to be able to dispatch it and reduce,
24 as the graph showed, reduce the customer load by a
25 commensurate amount. But also, on the flip side, if we

1 wanted to charge the batteries at night for the next day,
2 we've got to make sure that we're charging it in a smart
3 fashion so that we don't exceed the load management
4 threshold that we're trying to hold during the day. That's
5 the basic setup for what we're looking at now.

6 If we were to add, let's just say another level of
7 revenue opportunity on top of that, let's say at the -- I
8 don't know the terminology, it's not the neck of the duck,
9 whatever it is, the butt of the duck. Solar is coming
10 online. We have a lot of -- we have a distributed energy
11 resource asset that can charge and absorb some of that. And
12 there's a capacity charge for that. I would love to take
13 advantage of that and have my optimization engine, you know,
14 go to town and do the thinking that I can't do and figure
15 out how to do that. But my guess is, is that it's going to
16 have trouble figuring out how to value charging during the
17 day off of solar if it's off of grid solar, let's call it,
18 if it sets a new customer demand charge. Because then, from
19 an economic perspective, AMS, which is taking tariff risks
20 and offering savings to this customer in exchange for
21 hosting a battery, then we'll have to true up the savings in
22 some other way.

23 So all I'm suggesting is, you know, if Edison were
24 to offer a program that says charge during the window of the
25 morning when solar is ramping up, that can't be done in a

1 black box. It has to be done with consideration for what
2 happens after that.

3 COMMISSIONER MCALLISTER: Yeah. So I guess, you
4 know, so if I'm the ISO and I've got negative pricing on the
5 wholesale market, you know, and I've got a whole bunch of
6 solar, and yet, you know, you've got a commercial rate that
7 doesn't sort of transmit that incentive and has a whole
8 different way that demand gets set, you know, and it's --
9 maybe there's two different demands and they add up, that
10 seems like a mismatch between retail rates and the, you
11 know, the bulk grid. So I guess that's kind of what I'm
12 suggesting, you know, problems that we could talk about.

13 I don't know if, Tom, you've got any ideas about
14 that, but --

15 MR. SHERMAN: But I'll also add, sorry --

16 COMMISSIONER MCALLISTER: Yeah.

17 MR. SHERMAN: -- if I may --

18 COMMISSIONER MCALLISTER: Yeah.

19 MR. SHERMAN: -- just to cut in, I mean, I think a
20 good point was made about fleet optimization --

21 COMMISSIONER MCALLISTER: Yeah.

22 MR. SHERMAN: -- too. And there's a way to
23 satisfy both of those demands across a portfolio, whereas a
24 single site represents a lot of risk --

25 COMMISSIONER MCALLISTER: Uh-huh.

1 MR. SHERMAN: -- inherent in not being able to do
2 too many things at once. But --

3 COMMISSIONER MCALLISTER: Yeah.

4 MR. SHERMAN: -- to your -- you're making an
5 excellent point, too, about how there is a fundamental
6 mismatch sometimes. And I don't necessarily have a
7 solution. I think that is one of the fundamental issues
8 that we have to deal with.

9 COMMISSIONER MCALLISTER: And ideally you'd
10 have -- your client and your portfolio clients would see
11 those, the same signals. You know, the retail rates would
12 transmit that and everybody would be on the same page, so
13 hopefully we'll get there. So I guess --

14 MR. MURTISHAW: Commissioner McAllister, if I --

15 COMMISSIONER MCALLISTER: Yeah. Go ahead, Scott.

16 MR. MURTISHAW: -- could just add something --

17 COMMISSIONER MCALLISTER: Yeah.

18 MR. MURTISHAW: -- really quickly --

19 COMMISSIONER MCALLISTER: Yeah.

20 MR. MURTISHAW: -- to that? The point about
21 needing to -- in the same way that we're trying to update
22 the TOU periods to match current conditions, one thing that
23 I think we all need to start thinking about is the
24 appropriate application of demand charges and that
25 differentiating, which some of the utilities already do,

1 demand charges that recover costs that are marginal costs
2 that are related to serving coincident peak loads across the
3 system, or at least across large swaths of the system --

4 COMMISSIONER MCALLISTER: Yeah.

5 MR. MURTISHAW: -- so that you're charging those
6 demand charges or you're imposing them during those peak
7 periods versus any type of demand charge, which is non-
8 coincident, to recover the cost of providing the very, very
9 local capacity, you know, the facilities.

10 And so some utilities currently have those
11 structures, some don't. And we are still wrestling with
12 exactly how you allocate costs to each. But over time, I
13 would expect to see that coincident demand charges, like our
14 TOU periods, would also then move to reflect current
15 conditions, and so the companies wouldn't be penalized, in
16 effect, for taking on additional load, whether through
17 storage or just shifting usage into these super off peak
18 periods when prices might be negative. It really wouldn't
19 make any sense to give somebody virtually free wholesale
20 power, but then, you know, whack them at the end of the
21 month with this huge demand charge that was incurred at the
22 exact same time. So you're raising a good point there.

23 COMMISSIONER MCALLISTER: Okay. Well, thanks a
24 lot for that.

25 Let's see, I guess, you know, back in the day when

1 the CSI started, and, Scott, you'll remember this, you know,
2 there was a TOU requirement. And then the legislature --
3 you know, there was a total crisis that it generated in the
4 Inland Empire, and I don't know how many people remember all
5 this. But it was -- you know, the idea was that we wanted
6 to sort of condition the installation of solar with moving
7 over to more modern pricing. And you had, you know, people
8 who undersized their solar system and ended up with higher
9 bills and a solar system to pay for in the Inland Empire in
10 the middle of summer, which was not good, obviously. So,
11 you know, legislature sort of swooped in and nixed it.

12 But really, you know, in retrospect that was the
13 sellers of solar not really knowing what they were selling
14 and not understanding the implication. You know, of course
15 solar is good. We're going to go do it in the Inland
16 Empire. And eventually the solar industry figured out how
17 to sell solar, you know, and there was a huge valley
18 proposition. And, you know, it's not exactly the same.

19 But I guess to build on what the Chair said
20 before, it seems like there has to be an intermediary that
21 is in the marketplace packaging everything that you guys are
22 doing for your market segment, and you guys, as well, but
23 sort of taking this product, you know, call it DR, call it
24 demand flexibility, whatever, and making sure that the
25 customer benefits from it, but then taking advantage of the

1 grid needs to sort of create value right there in the middle
2 so the customer can set it and forget it and, you know, it
3 all works together.

4 And I guess with DR, you know, the question is,
5 you know, you were talking about residential, how automation
6 didn't seem like it worked with the Nest activity. And I
7 guess I'm wondering, you know, what do you all think the
8 product is or will be and what the ecosystem is that's going
9 to go out there and sell it and create value. I think about
10 that and I'm kind of wanting some insight from you all on
11 that.

12 MR. GEORGE: I'll go ahead and talk about the
13 residential customers. I mean, the example that Scott cited
14 about Nest and the treatment cell down in SCE, I wouldn't
15 run too far with that because it was -- you know, these were
16 current -- these were people who already had Nests and put
17 them on a time-of-use rate which is not a dynamic rate, and
18 really didn't really give them any extra information about
19 how to use the technology.

20 There's plenty of studies that show that with
21 dynamic rates, like critical peak pricing, that technology
22 does add a lot to the demand reductions. You know, it's
23 about a 50 percent increase if you had to take a household
24 with air conditioning and then give them load control, or
25 some PCT, or something like that --

1 COMMISSIONER MCALLISTER: Uh-huh.

2 MR. GEORGE: -- you'd probably get about 50
3 percent more in terms of demand response there.

4 But the Edison test was kind of -- you know,
5 this is a static time-of-use rate. By that I mean nothing
6 moves around, it's the same every day. And there was no
7 kind of assistance from Nest about how they could optimize
8 their energy use to take advantage of that rate. In this
9 next summer, I think they're -- Edison is planning to allow
10 Nest to provide that kind of assistance, so we might get a
11 different result there.

12 But, you know, it's kind of -- the whole
13 technology thing, I've been, you know, I've been hearing
14 about it for 15 years. And, you know, there's a couple of
15 comments.

16 I mean, I'm amazed at what residential consumers
17 can figure out and do without technology in response to
18 time-varying rates. I mean, every study shows that without
19 technology you get measurable and meaningful demand
20 reductions. And, you know, I've always -- one of my often
21 used quotes is never underestimate the value of a
22 thermostat -- I mean a refrigerator magnet. You know, all
23 they really need to know to understand a time-of-use rate is
24 static time-of-use rate is, you know, it's -- here's a price
25 during a peak period and here's a price doing the off-peak

1 period, do what you're going to do, and they do a lot. And
2 if it's a critical peak, you know, if you get an event call,
3 it's this big. So, you know, simple stuff like that works
4 well with static time-of-use rates.

5 Technology can add stuff with dynamic rates. I
6 think it's yet to be proven how much it will add with static
7 time-of-use rates. And I think -- but I think there's more
8 to study there.

9 With demand rates, you know, that's an unstudied
10 area for residential customers. I mean, there were a couple
11 studies done, you know, done in Duke in 1978 on demand rates
12 and what kind of -- you know, can people understand demand
13 rates? I mean, that's 40 years ago.

14 So, as I said before, I think there's going to be
15 a new round of pilots to figure out, you know, can
16 residential customers understand demand rates and different
17 kinds of demand rates.

18 The ConEd pilot that we're designing, which, you
19 know, the results won't be available until -- you know, for
20 a couple years, but they're looking at both demand
21 subscription rates, as well as a standard demand rate. So
22 we've got a couple of test cells to see how those might
23 differ.

24 And just what -- and then I'm trying to push a
25 dynamic TOU rate into it, I'm not sure I'm going to be

1 successful, so we can compare CPP rates versus demand rates
2 versus demand subscription service. I think that would be a
3 great side-by-side study. I don't know that I'm going to
4 get that third part to it.

5 But again, you know, I keep -- my answer to all
6 the questions is always let's study the heck out of it and
7 give you the answers you're asking for, rather than
8 speculate about it. And with demand rates, we just -- we
9 don't have a base of empirical research, but --

10 COMMISSIONER MCALLISTER: I guess my question
11 really was sort of, you know, how small is small? How small
12 is big enough to warrant some intelligent, you know --

13 MR. GEORGE: Yeah.

14 COMMISSIONER MCALLISTER: -- like intermediary
15 that can sell this, that can put the packages together, and
16 then can sort of let the customer sort of set it and forget
17 it --

18 MR. GEORGE: Right.

19 COMMISSIONER MCALLISTER: -- you know, big
20 commercial, you know, industrial. You know, there are
21 places where clearly that's going to work, you know, it's
22 happening. But, you know, is that ever going to work in the
23 residential where you actually have somebody knocking on
24 your door and saying, hey, you know, here's how you package
25 all this together --

1 MR. GEORGE: There's a lot --

2 COMMISSIONER MCALLISTER: -- and here's the
3 response --

4 MR. GEORGE: -- to learn there. In a separate
5 pilot, ConEd is looking at their smart home rate where they
6 do have much more complex rates, with the idea that
7 everybody needs technology. And we just finished about a
8 dozen vendor surveys of technology providers. And there's a
9 lot of technology out there that, in theory, can optimize
10 energy use and response to complex price signals. But the
11 customer interfaces don't exist --

12 COMMISSIONER MCALLISTER: Yeah. Exactly.

13 MR. GEORGE: -- for the small residential
14 customers, for sure. And, you know, so there's a lot of
15 work to be done there.

16 Some people are working on it. A lot of people
17 are working on the technology.

18 COMMISSIONER MCALLISTER: Uh-huh.

19 MR. GEORGE: Not very many at all are working on
20 the customer interfaces to allow the technology to work, you
21 know, in an effective way with small residential and small
22 business customers and stuff like that.

23 COMMISSIONER MCALLISTER: Okay. Okay. Thanks.

24 MS. DOUGHMAN: Oh. Oh.

25 COMMISSIONER MCALLISTER: I just had -- oh, go

1 ahead.

2 MS. RAITT: Just a time check. Sorry.

3 COMMISSIONER MCALLISTER: Sorry. Does anybody
4 else want -- I just have one more very quick question.

5 Nobody mentioned solar thermal -- or not solar
6 thermal, thermal energy storage for DR. I guess I'm
7 wondering if anybody -- that hasn't been on this panel at
8 all. I guess I'm wondering, you know, there are a lot of
9 examples around it. Is anybody talking about using that?
10 Are you guys thinking of doing thermal storage?

11 MR. SHERMAN: Well, on our website it says we're
12 technology agnostic, so, yes. Yeah, I think so. I mean, I
13 think what's attractive about the storage solutions that
14 we're working with right now is that they're instantaneous
15 and that we can -- they're very controllable, which isn't to
16 say that thermal storage can't be the same. We are looking
17 forward and always open to finding a commercial product that
18 we were able to monetize, yeah.

19 CHAIR WEISENMILLER: Thanks a lot.

20 MS. RAITT: Okay.

21 CHAIR WEISENMILLER: Let's go on to the --

22 MS. RAITT: So we'll take a short break. Let's
23 take a ten-minute break.

24 (Off the record at 3:40 p.m.)

25 (On the record at 3:53 p.m.)

1 MS. RAITT: So our last panel is on potential uses
2 of excess electricity. And Kevin Barker at the Energy
3 Commission is going to be the moderator for us. Thanks.
4 Oops, and I didn't change the slides. There we go.

5 MR. BARKER: Thanks a lot, Heather. Yeah. So
6 thanks.

7 Welcome back everyone. I know we're running a few
8 minutes behind, so I think we'll kind of change up the
9 structure of this panel just a little bit from the previous
10 two, especially that there isn't really a cohesive style of
11 glue that kind of brings a lot of these options or solutions
12 together.

13 What we tried to attempt to call this was excess
14 capacity and deal with this sort of nice issue to have of a
15 lot of cheap and carbon, either free or low-carbon intensity
16 electricity, what can we potentially do with that?

17 And so, you know, one option or, you know, a
18 couple options that we've thought about were, you know,
19 stuff that they're looking at in Europe, which is power-to-
20 gas. But then also, you know, another option where they've
21 really dove into in Australia and Israel of desalinization
22 and how to deal with, also, this other issue of lack of
23 water resources, clean water resources. And then we'll also
24 hear about flexibility of water conveyance at the last
25 panelist via WebEx.

1 So, you know, we hope to hear from the panel on
2 sort of the questions that we kind of laid out, but then
3 also sort of your take on where we're at, what you've
4 actually seen. And at least for the power-to-gas, we're
5 hoping not to hear that gas being really cheap right now in
6 California is the issue. I think that's probably a good
7 thing.

8 And so with that, I'll turn it over to Lisa with
9 SDG&E.

10 MS. ALEXANDER: Okay. Thanks Kevin.

11 So my name is Lisa Alexander. I'm Vice President
12 of Customer Solutions at SoCal Gas, a sister utility to
13 SDG&E. So I'd like to thank you on the dais, as well as
14 Kevin, for thinking to bring the gas lady to a discussion
15 about electricity, and I'm delighted to be here.

16 Many of you know, and especially in the last year
17 we've seen the effect of natural gas supporting generation.
18 So as we think of the duck, the tail and the neck, to a
19 large extent historically, have been powered by natural gas
20 peaking. And we're very proud to have played a significant
21 role through that peaking power to allow renewables to come
22 online in a way that supports both lower carbon goals, as
23 well as resilience.

24 We've also been experimenting with demand response
25 in the last year on the residential side. And we don't have

1 a lot of strong conclusive results today, but that's been
2 another area where our utility is willing to play, and
3 interested in seeing how far we really can push gas demand
4 response.

5 But as we consider the condition, as Kevin laid
6 out, of excess electricity, we're really excited about
7 having really what is in effect the largest battery for
8 potential renewable electricity available today. And we're
9 sitting on that, and that is our gas infrastructure. So
10 power-to-gas technology is the thing that activates this
11 infrastructure to be a large store of renewables without
12 concerns about dispatch, like we have with batteries,
13 without concerns about issues of mining and lithium ion --
14 excuse me, lithium ion batteries, without concerns of
15 recycling. So power-to-gas is a technology that we'll hear,
16 I think, a bit more about from Ivo that essentially converts
17 excess electricity into gas.

18 A few years ago the Germans realized this. They
19 realized the potential of this technology to solve, in their
20 area, a geographic issue where their renewable generation
21 was not lined up to match with their demand centers, but
22 their gas infrastructure was.

23 We have a temporal issue here with the duck curve.
24 And power-to-gas can play a similar role in resolving that.

25 So in Germany, they have about 30 projects

1 totaling about 30 megawatts worth of electric storage in
2 their gas system. So they take the excess wind mainly in
3 that country, convert it into hydrogen, and flow that
4 hydrogen through their existing pipeline infrastructure.

5 We have that here today at UC Irvine. So SoCal
6 Gas partnered with UC Irvine several years ago to support a
7 demonstration of the same thing. So what we're doing there
8 is taking the excess solar electricity from the university's
9 solar system and we're converting that into hydrogen. And
10 that hydrogen is powering a combined-cycle power plant.
11 What we see at UC Irvine is they're going from about a 3-
12 and-a-half percent utilization of their solar energy to a 35
13 percent utilization of their solar energy, because they're
14 able to capture it during that midday in the form of
15 hydrogen and use it to drive electricity in other parts of
16 their campus. So the results are still coming out on that,
17 but we're quite excited about the potential of that on a
18 utility scale.

19 So as we think -- I'll comment briefly and then
20 turn it over. And I know Kevin and you will have questions.
21 But as we think about the next step, what we would really
22 like to see is a pilot, a demo of scale, utility scale, to
23 show how power-to-gas can work here, like it does in
24 Germany. So to site a power-to-gas facility at the source
25 of renewable electricity to convert it into the gas and then

1 to use the storage -- the existing storage infrastructure to
2 transport and store that.

3 There are a number of barriers. I'll touch on a
4 couple of them. One is that today, power-to-gas does not
5 count or isn't considered conventional storage. It doesn't
6 meet the definition. So the electric -- electricity-to-
7 chemical process is not a pathway that's currently
8 contemplated in the PUC Regulations. So that's one thing
9 that we would need to address.

10 The second thing is that today electricity is
11 really the feedstock for power-to-gas. And there currently
12 is a wholesale rate for that feedstock for the power-to-gas
13 pathway. So to have that be available at a wholesale rate
14 would also be advantageous from a financial perspective to
15 bring this on.

16 The third thing is that right now the product of
17 power-to-gas is initially hydrogen. Now our system, we're
18 currently comfortable with less than one percent hydrogen
19 flowing through our system, blended with regular methane or
20 natural gas. Hawaii has up to ten percent. Germany has ten
21 percent. So we do have a research study where we're trying
22 to evaluate, what is the right percent? What are the
23 effects of too much hydrogen? How do you mitigate for those
24 effects? So that's one path of research that needs to be
25 further developed.

1 The second path of research is methanation. So
2 this summer we'll be launching a new study with NREL that
3 uses microbes to create methane out of the hydrogen and a
4 carbon source, a carbon dioxide source, to turn it into CH₄,
5 which is the basis for natural gas. So methanation
6 introduces complexity and cost. There are some ways to
7 mitigate that, for example, siting a facility at a
8 wastewater treatment plant where there is already the
9 feedstock for the methane there.

10 But those are a couple of examples that we are
11 investing in research and development. Our assessment is
12 that it is possible to get past those. Our recommendation
13 is to start now with hydrogen and get that flowing. And
14 potentially today it flows straight to the hydrogen fuel
15 cell market. But in the future, again, we would strongly
16 encourage policies and regulation that would support using
17 the existing infrastructure as that battery, a renewable
18 battery, using the power-to-gas technology.

19 MR. BARKER: Thanks a lot.

20 So we'll go next to Ivo, who is CEO of Aquahydrex,
21 a power-to-gas company.

22 And one thing that -- when I heard about his
23 technology, probably about a year or two ago, the inherent
24 potential for flexibility in there is one thing that I
25 thought was pretty interesting.

1 And so please, go ahead.

2 MR. STEKLAC: Thank you very much. And thank you
3 for the opportunity to address the panel today.

4 If we can go to the first slide?

5 So the topic of the panel is very interesting, how
6 to increase load flexibility. And I'll maybe start by
7 saying, how about providing access to three times as much
8 load as is currently served by the existing electric grid in
9 California? And the reason for that is that hydrogen
10 enables a pathway to replace fossil fuels. And those fossil
11 fuels today represent still three times more energy
12 consumption in this state than electricity alone.

13 And the method by which we do this has actually
14 existed for quite some time. Electrolysis was discovered in
15 1800, so it's 217 years old and relatively tried and trued.
16 What's been the fundamental problem in making electrolysis
17 costs effective is twofold, the basic technology and making
18 it more efficient, something we believe we've solved, but
19 more importantly than that, the variable cost of the energy
20 that is needed to power it. And as we see the inexorable
21 ramp down in cost of renewable energy, we are now getting to
22 the point where we can have source energy that is
23 inexpensive enough to power electrolysis, together with the
24 grid, and actually provide that conversion of carrier from
25 electricity to a hydrogen atom.

1 If you will allow me to talk to this slide a
2 little bit, we believe that this is an incredible
3 opportunity fundamentally, because once we have hydrogen
4 it's a completely green gas. There is no way to combust or
5 use hydrogen that will actually emit any type of pollution
6 or any type of greenhouse gases. So it actually helps us in
7 our goals of decarbonization and reducing pollution.

8 Furthermore, it can be transported by all of the
9 existing fossil fuel and gas transport mechanisms, whether
10 that's injected into the natural gas pipelines or moved by
11 containers and ships and trucks to the ends -- points of end
12 use.

13 And what it allows us to do is it enables us to
14 tackle transportation. And so it's an additional way of
15 tackling transportation from the standpoint of fuel cell
16 electric vehicles, but even more so from the fact that
17 refineries today consume an incredible amount of hydrogen.
18 So 2,000 metric tons of hydrogen get consumed in California
19 daily, mostly by refineries. And unless those refineries
20 are doing something specific with the carbon dioxide that
21 gets emitted through the formation of that hydrogen, those
22 2,000 tons are generating an equivalent of 17,000 tons of
23 CO2 on a daily basis. And replacing that with a renewable
24 hydrogen or with renewable hydrogen could eliminate all of
25 that capability.

1 Furthermore, it allows us to decarbonize industry.
2 So to what Lisa was also talking about, if you take
3 hydrogen, add carbon dioxide, you have the hydrocarbon
4 building blocks of all of the other chemical processes that
5 industry utilizes, which allows us to even go beyond just
6 how much energy is consumed by industry, but also enable
7 that to become a renewable feedstock, particularly if we
8 used captured CO2 to deliver that.

9 And then finally, it can also help us with heating
10 and the rest of our -- the rest of our energy uses.

11 And as a final point, it can provide a lot of
12 resiliency to the grid, as well, and I'll talk about that
13 next, but as well as storing of energy.

14 So if we could go to the next slide? Sorry.

15 So in talking about grid resilience, electrolyzers
16 are incredibly fast reacting machines. In fact, as soon as
17 you apply energy to them, they begin to create hydrogen. So
18 several studies have been performed. I site two here from
19 NREL that show how an electrolyzer can provide regulation,
20 so up and down regulation in the electric markets, how it
21 can do fast load and energy following, how it can basically
22 provide spinning reserves, and then even non-spinning
23 reserves.

24 So by coupling these to the grid, we can absorb
25 all of the variation of the renewables. We can abate the

1 curtailment of renewables we're seeing today because we have
2 a way of consuming all of that excess energy, converting
3 that energy to hydrogen, and then being able to use that
4 hydrogen energy in an alternate -- in that alternative form
5 later in the same day, next week, or even months later. And
6 I think that that's equally important as a storage
7 mechanism. And we'll talk a little bit about that coming
8 up.

9 Next slide please.

10 So this begins to talk about that. So if we look
11 at the two-minute profile of renewables, they're highly
12 volatile. So you need something that can track those
13 renewables extremely quickly and well. And as I showed on
14 the last slide, an electrolyzer -- electrolyzers have that
15 ability.

16 Furthermore, they have an ability to ramp
17 extremely quickly and dynamically. Similar to solar, they
18 have a voltage-to-current characteristic where they can
19 operate at an optimum point, which is where they can operate
20 an optimum point, which where we operate them for the
21 optimum conversion economically. But you can drive them
22 significantly past that, increase some of what we call the
23 Ohmic losses or resistive losses in the conversion process,
24 but be able to absorb that much more energy. And that's
25 really useful when we're having issues where we're having to

1 do emergency curtailment on the grid because we've got
2 excess capacity and aren't able to do anything with it,
3 either during the day with solar or at night with wind.

4 And then finally, the top curve -- or the top
5 graph tries to demonstrate that equally, we can also provide
6 seasonal storage. Because as we have more and more
7 renewables on the grid the seasonal differences between
8 winter and summer for both solar and wind begin to affect
9 our dynamics of the grid quite a bit more. And by
10 conversion to hydrogen we can maintain that hydrogen in a
11 non-loss for that duration, and even then some.

12 And that brings me to what I think is my last
13 slide, if I may, and that's hydrogen-to-storage. And so I
14 cite a report up here that came out of the European
15 Commission as they were looking at their winter package and
16 trying to define storage and market regulations. And I
17 think what's fascinating is if you look at the very bottom,
18 conversion of electricity, renewable electricity to hydrogen
19 and then back to electricity through a combined-cycle power
20 plant can actually beat the cost of pumped hydro storage
21 when you look at long duration storage, and that's storage
22 in excess of 2,000 hours. And again, that storage can be
23 found from existing facilities, like natural gas pipelines,
24 existing underground storage, as well as tank and similar
25 storage mechanisms.

1 And so this actually had the European Commission
2 propose a change of definition of electrical storage to be
3 defined as the text as you see there, energy at its end
4 point of use or energy converted to another carrier. And
5 that's now before the European Parliament. And if adopted
6 will be spread across the 27-member states, which enable
7 power-to-gas.

8 So in talking to some of the barriers, Lisa
9 mentioned the key ones today, conversion from energy from
10 electricity to another carrier, such as hydrogen, is not
11 considered storage in California, nor do we have the ability
12 to access wholesale market rates that would enable us to be
13 even more cost effective. We can access very inexpensive
14 electricity by tying directly to renewables, but that then
15 loses the ability to provide all the integration and grid
16 benefits of a rapidly responding load that can absorb the
17 variations of the grid.

18 And I think perhaps as a higher level item, I
19 think what's missing a little bit is the ability to think of
20 energy in this sector-coupled fashion, and with that, I
21 think we're losing some opportunity. Because by being able
22 to take electricity and electric -- and what we want to do
23 in achieving our greenhouse gas and pollution abatement
24 goals is we want to electrify more and more of our systems.
25 Hydrogen enables that electrification literally to all of

1 our energy consumers, as well as our chemistry -- chemical
2 industry, as well.

3 And so looking at how policy and operations think
4 about sector coupling would, I think, also be something that
5 we would endorse, and thank you.

6 MR. BARKER: Thanks a lot, Ivo. Really appreciate
7 it.

8 Next we have Graham from Poseidon. He's -- thanks
9 for coming up again. He's become our sort of token desal
10 guy. But I know you do also want to talk about sort of the
11 water system in general and how it can lead -- it can help
12 with this flexibility need in the electricity system.

13 So please go ahead.

14 MR. BEATTY: Yeah. Thank you, Kevin. And thank
15 you again for having me here this afternoon.

16 So a quick refresh. Poseidon Water is a water
17 infrastructure developer. We built the Carlsbad
18 Desalination Plant, which has been up and running for almost
19 a year-and-a-half now. You know, the plant is performing as
20 expected. It's about a 30 to 35 megawatt load. And what we
21 learned is that through our interaction with our customer,
22 we're actually able to drop load fairly quickly, which kind
23 of lends itself to a demand response mechanism in the water
24 treatment space, and specifically in desal. So empirically,
25 we can already prove that, which is definitely a positive

1 for our grid management going forward.

2 So kind of what's going on in water development in
3 the water-energy nexus, if you look behind the dais here, I
4 challenge you, and next to that energy bolt, I would say
5 that's a water drop right there underneath the bear. So --
6 and I think it's -- what we have an opportunity for is
7 really load shifting and demand response in the water
8 industry. Now in the water industry, it's pumps, it's
9 membranes, it's tanks. It's not a concrete manufacturer
10 where we have to figure out your shifts or personnel. It's
11 not a residential customer that may not care.

12 You know, we have a limited number of institutions
13 who care very much about how much they're paying for power.
14 And so if we can isolate these constituents, I think there's
15 really an opportunity to do all that with demand response
16 and load shifting because of the ability of water pumping to
17 shift around load.

18 What are some of the barriers to load shifting and
19 demand response. On the chemical side, it's already been
20 proven in the Middle East that we can pair desalination and
21 water treatment with renewables. So from a technical
22 standpoint, we really don't need to go into a better
23 mousetrap. And furthermore, it's not just ocean
24 desalination we're talking about. It's also portable reuse
25 for recycling, advanced sewage treatment. These all just

1 involve the general concept of pumps and membranes that can
2 be ramped up and ramped down according to a power profile.

3 What's more important is that we need to plan for
4 this. You know, we need signals to make sure that if we
5 make the capital investments into load shifting, that it's
6 going to make sense in the long term, because we do have
7 some challenges. To load shift, we will likely incur some
8 more O&M costs, you know, so it will be more wear and tear
9 on the pumps themselves. And it's also important to
10 understand that, unlike a battery which can just charge and
11 discharge, we also -- we're not only just balancing an
12 electrical problem, we're also balancing a water problem.
13 And so to the extent that we can build larger water tanks,
14 we can still supply our customers/consumers with water by
15 ramping our flow on one side. So the concept is you're
16 filling up the tank and discharging to the tank at a
17 variable rate, but you're pushing that product water to your
18 customer at a constant flow.

19 The second piece is that whether it's ocean
20 desalination or, you know, advanced treatment, you also have
21 to think through the size of your intakes. These are
22 heavily regulated industries. And so we can't just go out
23 there and build a new intake that's allowed to flow more
24 water during the middle of the day when there's a surplus of
25 energy and ramp back down. So to build a larger intake, to

1 build these larger capital-intensive systems, you know, it
2 takes multiple years of permitting to go ahead and design
3 these facilities in the right way.

4 So to the extent that we can get better visibility
5 in how the tariffs will look like in the future, and we
6 touched on this a little bit today where we see the on-
7 peak/semi-peak/off-peak pricing, but there's still a
8 significant amount of the energy bill allocated to demand
9 charges. And to the extent that we can shape these tariffs
10 where we can incentivize the water industry to not get
11 penalized for shifting their load, I think that's really
12 going to go a long way towards developing the industry.

13 So just to wrap up here, you know, there are real
14 grid benefits here. The challenge, though, is because water
15 infrastructure takes time to develop, just like energy
16 infrastructure, we really need better signals now, because
17 that means that the plants that are developing in five or
18 ten years will be able to take advantage of the surplus
19 renewable energy and provide a grid benefit with demand
20 response and with load shifting. And if we wait for 10 or
21 20 years for kind of the tariffs to shake out, that's going
22 to be another 20 years until the systems actually get built.

23 So what action is needed? I think what we're
24 really trying to figure out is how can we get a better
25 transparency into what direction the general energy markets

1 are going. And then we -- then I can go back and make a
2 recommendation to investors who are willing to take a risk
3 on, you know, a higher capital investment for, you know, for
4 load shifting.

5 So I'll wrap up with that, and thank you for
6 having me.

7 MR. BARKER: Thanks a lot, Graham.

8 So for our last, what I'll call presenters than
9 panelists, Dr. House is an Energy Consultant for AQUA. And
10 he is going to participate via WebEx to talk about how the
11 water system can help with this issue.

12 So, Dr. House, go ahead.

13 MR. HOUSE: Well, thank you for having me. And
14 I'm going to talk about how the existing water system, as
15 it's configured in California, and with some changes, what
16 it can do.

17 Just sort of to set the parameters, and I'm
18 talking about customers of electric utilities. I'm not
19 talking about DWR, which is doing a really good job of
20 shifting load. But for customers of the electric utilities
21 there's about 3,000 megawatts of on-peak demand. They are
22 now currently dropping between 400 and 600 megawatts every
23 summer afternoon, and this is through a culmination of the
24 water demands and the ability that they have for storage.

25 The issues, there are a couple of institutional

1 issues. One of the issues that we have is that water
2 deliveries on a wholesale basis and on an agricultural basis
3 are on a 24-hour window. So you will put in your request
4 for water, you have to take exactly the same amount of water
5 over every hour for the next 24 hours, otherwise there's
6 problems with the canals. And there are -- and so -- and
7 then the agricultural sector, the plots have been
8 established to accept this 24 hours of constant water
9 deliveries.

10 For the urban areas, they have a very distinctive
11 bimodal daily peak. There's a peak for water delivery in
12 the morning before people leave for work, and there's a peak
13 for water delivery in the evening when people come home.
14 And the systems are configured so that they meet that peak
15 in the evening, which is the maximum peak of the day. So
16 they will use water in storage. They'll fill their water
17 storage up and they'll use water in storage to make it
18 through the afternoon. And then in the evening is when
19 they're running their pumps and their water storage.

20 So even on the existing systems, and we're looking
21 at several systems right now addressing the time-of-use
22 period shift to look at what they can do, increasing the
23 pumping in the afternoon, which they've never -- they
24 haven't done before. They've pumped in the evening, had
25 their tanks full at six o'clock in the morning, and then

1 basically drained them throughout the day, and then drained
2 them and used pumps in the evening, and then started
3 refilling at night.

4 So there are opportunities to do that with the
5 existing system. I don't know -- we haven't determined
6 exactly how much there is there, but it's probably hundreds
7 of megawatts that could you use in the afternoon to refill
8 your storage tanks, which the water systems have avoided
9 thus far.

10 The last thing I want to talk about is a very
11 interesting set of studies that the Energy Commission has
12 funded. And this has to do with what's called aquifer
13 storage, or what is called conjunctive use, or its
14 groundwater storage, which is taking surface water and
15 storing it under the ground. And there are dozens of these
16 fairly large projects throughout the state. So this
17 particular study that was funded by the Energy Commission
18 was to look at -- and it has to do with an Antelope Valley
19 storage project called Willow Springs Water Bank which was
20 to look at how we could convert this into a pump storage
21 facility.

22 Because basically when you -- we're pulling water
23 out of the ground, you're pumping it out, and if you --
24 depending upon the configuration in the system, if you
25 install hydroelectric generators, you can create energy,

1 create electricity when you're sending it back into the
2 ground.

3 So if you can flip to the next slide?

4 These are some preliminary results, and I think
5 they're really encouraging. What this shows it this is an
6 initial result. And what I was using here was SCE delap
7 (phonetic) prices. So this is just based upon the economics
8 of the daily prices. And this was a figure for January. So
9 the bars that are above the line are when the project is
10 generating electricity. And you can see, it's generating in
11 the morning ramping period and it's generating in the
12 evening ramping period. The bars below the line are when it
13 is pumping water out of the ground, so that is the increased
14 load. So you can see for January, it's doing almost exactly
15 what we want it to do.

16 The next slide is an April slide in which it's
17 doing very, very similar things. It is generating in the
18 morning. And it is increasing load in the afternoon to pump
19 water out of the ground. And it is generating in an evening
20 ramping period.

21 So these studies are ongoing right now. But this
22 has the potential for doing -- solving a lot of the issues
23 that we're looking at, which is increasing load in the
24 afternoon during the solar maximum period, and generating in
25 the morning ramping period and the evening ramping period.

1 Now what we're looking at is looking at what happens to the
2 aquifer and whether we could use it for demand response and
3 things like that. But there is considerable flexibility
4 within the existing water system, and with examples like
5 this, which -- with enhancements to the water system.

6 But I want to further Graham's comment that the
7 water systems in California have been built over the last 30
8 years. And this time-of-use period shift has really kind of
9 got them slapped upside of the head because -- and they are
10 very, very reluctant to invest in changes in their
11 infrastructure unless there is some sort of a guarantee that
12 next rate case, they're not going to whipsawed again.

13 So, you know, one of the things that we've seen at
14 the Public Utilities Commission that we've advocated for is
15 that the time-of-use period changes will be fixed or a
16 minimum of five years. That -- we need something like that
17 because we need to have some stability in rates so that we
18 have an investment horizon so that we can look at whether we
19 can make these infrastructure changes and recoup the costs
20 without having the ground and the rates yanked out from
21 under us.

22 So that's my comments for today. Thank you.

23 MR. BARKER: So with that, we're a little bit
24 behind, but I'll turn it over to you, Chair Weisenmiller,
25 for our questions.

1 CHAIR WEISENMILLER: Yeah. A couple questions.

2 So, Lon, I don't know if you listen to -- this
3 morning we had -- Mark Rothleder gave -- actually, probably
4 all of you, I should say -- Mark gave a pretty good
5 presentation that was pretty data intensive on when we have
6 excess power, when, you know, we have negative power prices.
7 And obviously, it's not like it's a continuous thing, you
8 know, periods and days, and depending upon months, what time
9 of the week it's going to occur, but basically starting to
10 think about what that means.

11 And following up on the next part, if you also
12 heard, and again, you know, before you get to your written
13 comments, Lon, you may want to look at it, Bonneville's
14 presentation, obviously, Bonneville was facing, which I
15 think many of your people are facing, Lon, that wholesale
16 prices are going down, and at the same time there's sort of
17 surplus power which, you know, we're looking at it can go
18 out of state, it can go to desal, and god bless, it could be
19 stored in the California hydro system. So it's both a
20 challenge, I think, in terms of wholesale prices and
21 opportunity in terms of surplus power.

22 And I know, again talking to the Germans, I mean,
23 they would love to have the water system we have to help
24 them address some of their issues. So certainly getting
25 your thinking and more thinking by your clients on both the

1 challenges and opportunities would be very helpful in this
2 context.

3 Switching to power-to-gas for a second, I would
4 note, first of all, you know, which people here hear, and
5 they'll certainly here when we get to the renewable gas
6 workshop, is that we have to, in our gas system, deal with
7 leakage, and we have to deal with safety. I don't care if
8 it's renewable, gas, whatever. If we have another San
9 Bruno, it's all over, you know? And certainly if the stuff
10 is leaking out, again, either you've got safety
11 implications, or certainly climate implications.

12 So, you know, it's really important for the gas
13 system that that really be upgraded.

14 Now I would note, President Picker and I,
15 actually, before he was on the PUC, went to Germany. We saw
16 a commercial scale power-to-gas unit. And I would say when
17 talking to Germans, they're -- and a lot of this comes out
18 of research you can read by -- in Agora Consulting Firm
19 (phonetic) before their energy minister became energy
20 minister. But anyway, the way they see it for storage, one
21 is through the grid, i.e. they would like store as much
22 power as they can in Norway. It's cheap. It's easy. Now
23 technological challenges, I mean, it's a no-brainer.

24 Thermal storage, again, commercially available.
25 They're trying to get as much thermal storage as they can.

1 Batteries they say is more -- you know, again,
2 this is awhile back, but certainly figure is California
3 could take on trying to commercialize batteries. They had
4 driven down the cost of photovoltaics. They wanted someone
5 to drive down the cost of batteries, and they weren't going
6 to volunteer.

7 Power-to-gas, they just saw off the charts in
8 terms of price. And as I said, we went to commercial
9 operations. We saw it as, you know, yeah, hydrolysis has
10 been around for a long time. It's not the issue. And for
11 them, you know, it's looking at the option or Russian gas.
12 And so anything looks attractive relative to Russian gas.

13 But having said that -- and they have a much
14 different issue, they have the seasonal issue. You know, if
15 you go to Germany in May, you know, they probably have 100
16 percent renewable. If you go to Germany in January, which
17 is their peak, there's very little sunlight, and so they
18 need to figure -- and that's when their peak is. So they
19 have a real seasonal problem and they have a real supply
20 problem. But it was -- even with commercial power-to-gas,
21 it was not a happy story there, you know, a much tougher
22 situation than here.

23 So part of the question for all of you is, A,
24 safety on the system and, B, getting the costs down, you
25 know? And so, you know, how do we get the -- how do we --

1 you know, commercial would be good. I've seen the
2 commercial, Picker and I. There are pictures on the
3 internet of Picker and I standing in front of one of these
4 things. But as long as it's too expensive or it's not safe
5 it's not going to go anywhere.

6 MR. STEKLAC: Sure. Maybe I'll touch on -- I'll
7 touch on expense first.

8 So part of the problem is that in Germany, similar
9 to what we have here, is what rate can you access and when;
10 right? One of the ways that Germany today basically gets
11 back the increased cost of all those renewables on the grid
12 is through a levy for renewables that is imposed on all
13 endpoint, end use electricity consumption. Until that
14 definition that I showed is past, an electrolyzer that is a
15 grid resource is considered end use energy consumption. It
16 is not a grid resource. It's not a battery. So therefore
17 it's paying the retail rate for electricity.

18 So when you look at the retail rate of electricity
19 you cannot convert it cost effectively to hydrogen, no
20 matter how efficient the electrolyzer would happen to be.

21 When you look at wholesale rates or even the
22 marginal rates, so equally German just had their last wind
23 tender that closed just last month, and they came in at zero
24 marginal cost in terms of wanting additional monies, right,
25 in that less than four Euro cents a kilowatt hour. So when

1 you look at those types of rates as the wholesale rates,
2 then we actually can be efficient. And that is what that
3 storage study that I cited that showed us three times less
4 expensive than pumped hydro, which is the least expensive
5 today long-term energy storage that we can find.

6 And I'll let Lisa address some of the safety
7 issues.

8 MS. ALEXANDER: Okay. So San Bruno was a tragedy.
9 There have been a number of other examples of that. I think
10 there are many who would also argue that Aliso Canyon was an
11 environmental tragedy, and for some also of health effects
12 tragedy.

13 I think many of our colleagues would -- feels very
14 strongly about an electrification strategy, and I think our
15 company would certainly disagree with that. Where I think
16 we can agree is on a decarbonization strategy. So we'll
17 speak more about it in the renewable gas workshop.

18 So I think if you believe and if you know that the
19 gas system has served millions of people and industry for
20 decades, SoCal Gas, 150 years, and that there are rigorous
21 regulations at the federal and state level regarding safety,
22 and that we are incentivized and take very rigorous
23 practices to make sure that the system is safe, if you
24 believe that there is value in the gas system, and I think
25 many do, I know that more than 90 percent of people who use

1 natural gas today for reliable and efficient heating do, we
2 know that the industry -- Los Angeles is one of the main --
3 largest manufacturing hubs in the United States which is
4 just kind of bizarre. When you think about that, you don't
5 think about it as an industrial town. But we have a lot of
6 production and jobs there that rely on the heat of natural
7 gas.

8 So I know from our company's perspective is that
9 we do everything to our utmost ability to assure safety. We
10 have a number of practices that we do -- that we apply to do
11 that. We constantly work with experts. So I think that
12 that is really not an issue as we think about power-to-gas.

13 Now the efficiency question about leakage, EDF is
14 certainly noted and made very public a number of leaks on
15 gas systems. I can -- I'm very pleased to report that many
16 of the leaks that are characterized as national issues are
17 less significant here in California where our pipe system is
18 much newer. We don't have cast iron at all in our system,
19 for example. So we see a lot of that more on the East
20 Coast. But from an efficiency perspective in terms of
21 transporting renewable materials, I would argue that we see
22 line loss and other inefficiencies on the electric side, as
23 well.

24 I think as we think about renewable storage, to
25 Ivo's point is that gas infrastructure can support long-term

1 storage, so six to eight hours or longer in terms of
2 supplying really large volumes of renewable.

3 So I think those are my comments.

4 There are a number of proceedings and other things
5 we're involved in on the topic of safety. But again, I
6 would just go back to the over 90 percent of consumers who
7 rely on and depend on natural gas and where there aren't
8 incidents. I would also point to the number of safety
9 practices that we have applied over the years and continued
10 to apply to make sure that our system is hardened and safe.

11 CHAIR WEISENMILLER: Well, certainly we're lucky
12 we don't have to put in a hydrogen infrastructure system.

13 MS. ALEXANDER: Well, you know, that's something
14 some people do talk about is the --

15 CHAIR WEISENMILLER: I've heard that in --

16 MS. ALEXANDER: Yeah.

17 CHAIR WEISENMILLER: No. Yeah. We don't need --

18 MR. STEKLAC: The point, in fact, is there are
19 actually quite a few of them already around; right? So, for
20 instance, there is a hydrogen pipeline system that does feed
21 most of the refineries here in California and in other more
22 refinery-intensive states in the U.S., as well.

23 And maybe I'll add one other -- one last aspect in
24 terms of emissions and climate impact, is hydrogen is the
25 third most abundant element on the planet, yet it exists

1 less than one part per million in our atmosphere. And the
2 reason for that is that if hydrogen does leak, it basically
3 goes straight into space. And it has no greenhouse gas
4 impact when it does so.

5 MR. DOUGHTY: Lisa, you mentioned the variation in
6 the percentages of hydrogen that might be put in a piping
7 system, and it seemed quite wide to me, Hawaii, ten percent,
8 we, one percent. What's the defining factor? Is it
9 corrosion, is it --

10 MS. ALEXANDER: Yeah. That's a great question.
11 It's one we're still trying to get our head around. You
12 know, our specs, what we feel comfortable with, given the
13 characteristics of our pipes, it's less than one percent.
14 But Hawaii Gas, as I mentioned, has ten percent. So --

15 CHAIR WEISENMILLER: Hawaii Gas has an extremely
16 leaky system, extremely leaky.

17 MS. ALEXANDER: Yeah. Well --

18 CHAIR WEISENMILLER: Yeah.

19 MS. ALEXANDER: -- and part of it, too, is that
20 our understanding is that the hydrogen, because the
21 molecules are smaller, can cause corrosion that you wouldn't
22 otherwise expect to see in the natural gas system for which
23 there may not be a lot of significant practices to mitigate.
24 So -- but I also understand that much of Hawaii Gas's
25 pipelines have a different material science than much of

1 what we have.

2 There are a number of research projects at the Gas
3 Technology Institute that are trying to understand, you
4 know, how is ten percent possible, less than -- try to
5 understand exactly what you bring up.

6 So I'm sorry I don't have a specific answer. But
7 I can tell you, a lot of people share that same question,
8 yeah.

9 MR. DOUGHTY: I did have a question for Lon. Lon,
10 good to hear your voice. Tom Doughty here.

11 In your graphic, I didn't see the units on the
12 left-hand column for the test projects that you did. Are
13 those in watts or are those in what, the left-hand axis, I
14 should say?

15 MR. HOUSE: Those are actually in kilowatts. So
16 the pumping portion, which is below, is about ten megawatts.

17 MR. DOUGHTY: Uh-huh.

18 MR. HOUSE: And the generating portion is about
19 five megawatts.

20 MR. DOUGHTY: Okay. Those are significant numbers
21 then. Yeah.

22 MR. HOUSE: Yeah. And this is a pretty small
23 facility. So I think if the system is configured
24 properly -- and it's not available to all of them. There's
25 a bunch of them that are in the San Joaquin Basin,

1 semitropic and (indiscernible) Edison, that area is so flat,
2 they don't get much -- they can't put upper level storage
3 and get much hydrogen -- or much electrical production, but
4 there are a number of them. And if this turns out -- if we
5 can make sure that the aquifer doesn't get messed up with
6 this constantly sort of coming in and going out, then this
7 has the potential to, I think, be very, very useful.

8 One final comment, though, talking about the
9 various systems, remember, the water systems, their job is
10 to provide water. So they are not going to be necessarily a
11 dedicated electric utility demand response or pump storage
12 facility. Because when they've got the water deliveries
13 that are required, they're going to use it out of storage or
14 they're going to use it from their tanks or something or
15 some other parameter. So these are not really dedicated
16 facilities.

17 However, this study that we're doing right now,
18 this is actually a dedicated facility, which is just we're
19 just pumping water back and forth underground or using it to
20 generate electricity solely based upon market prices.

21 MR. DOUGHTY: Understood. And I suspect that as
22 these pilots begin to pan out and show results, that
23 additional facilities might become available as people see
24 the financial merits of participation.

25 MR. HOUSE: Yes.

1 MR. DOUGHTY: Lon, are these -- these are pumps
2 that are buried then into the ground, because any pump
3 storage project operates off of an elevation head, right, a
4 difference in altitude. So these have to be dropped down in
5 quite far into the ground; is that correct?

6 MR. HOUSE: Well, on this particular facility,
7 that's not the case. So what we've got is when you're
8 pumping the water out of the ground, it's just the regular
9 groundwater. But what we're doing is we're pumping it into
10 an upper level reservoir, and then we're dropping it back
11 down. And it's just spread on the fields and going back
12 into the ground. So it just -- the hydroelectric generators
13 just look like regular hydroelectric generators.

14 MR. DOUGHTY: Got it. Thank you.

15 MR. HOUSE: There is a potential for reversible
16 pump turbines underground. That's not what this study is
17 looking at. And there are issues with using reversible pump
18 turbines underground, but that's sort of the next phase, you
19 know, we may look at. They're not as efficient thus far as
20 having just a pump and having a hydroelectric generator.
21 But theoretically, they could work.

22 MR. DOUGHTY: Thank you.

23 COMMISSIONER MCALLISTER: I just have one question
24 for Graham. What's the sort of plant factor or capacity
25 factor of Carlsbad. And I guess, you know, could you talk

1 about some of the factors that might go into sizing desal
2 plants, or dimensioning them and designing them to really
3 be, you know, more of a kind of a dump load, you know, that
4 you don't have to operate 24/7 and --

5 MR. BEATTY: Sure.

6 COMMISSIONER MCALLISTER: -- sort of how to be
7 responsive in that way?

8 MR. BEATTY: Yeah. So Carlsbad is a 50 million
9 gallon a day plant, which is about ten percent of San
10 Diego's water. In the Middle East they go up to 200. So
11 you can build these things as large as you would like
12 because essentially there modular. You can just kind of --
13 unlike one single turbine or something, you can actually
14 building these trains right next to each other and can build
15 it as small or as large as you would like. Typically you
16 build big because of the economies of scale.

17 So for 2 million gallons, that's about 30 to 35
18 megawatt load. And you could probably load shift, if we
19 were really aggressive and everything worked out great, 100
20 percent of that load. It would ramp all the way down during
21 a peak event and ramp all the way back up during an off
22 peak. But more realistically, you know, probably a 50
23 percent shift, you know, so you're talking up to 45, down to
24 15, because if you want to keep some of that facility
25 running and wet and you want to continue some level of load

1 to your -- or product-wide deliveries to your customer. So,
2 you know, with the right pricing mechanisms it really does
3 pencil out. I've run some numbers myself.

4 But a very specific challenge, at least to ocean
5 desalination, is that these intakes are extremely heavily
6 regulated. And so if you were to, you know, to consume more
7 power, you need more water to flow through the system, which
8 means a larger intake; right? And our state agencies right
9 now really don't like large intakes in any shape or form.
10 Their preference is subservice intakes which have their
11 challenges, especially if you're trying to like increase
12 flows or not. And then if you do a screen intake, you have,
13 I think it's a half-a-foot per second flow challenge. So
14 you can't rush that water through that pipe too much because
15 of entrainment or impingement of organisms, so it has to be
16 slowly moving water into the system, which means you'd have
17 to build a larger pipe.

18 So that's the real challenge there from an
19 implementation standpoint is, you know, how can we work with
20 other state agencies to see the benefit of, you know, a
21 zero-carbon impact desal plant versus how you make the most
22 of your marine resources?

23 CHAIR WEISENMILLER: Well, again, I think what
24 we're trying to explore here, and certainly encourage people
25 in their written comments to develop off of that, is I think

1 we're -- with Mark's presentation this morning, there's a
2 lot of information about, at least, the current patterns.
3 And it's a high hydro year, you know? But we're going to
4 add a lot more renewables over time. If you look at some of
5 the ISO forecasts, you know, there's substantial amounts of
6 very low-cost power that we're looking for. And, you know,
7 it could go out-of-state. It could go to a variety of
8 things. But certainly, if it can help build the economy in
9 California, that's great.

10 And, you know, certainly one of the things we
11 really want to explore is, again, one of our unique
12 resources is the water system we have, you know, moving
13 water around, potentially producing water, potentially, you
14 know, the wastewater, you know, just that whole complex of
15 stuff. Water, you know, is certainly critical in
16 California.

17 I think on the power-to-gas issues, like I said, I
18 think, you know, the public will just have to deal up front
19 with leakage safety. And I think as you look at the options
20 here, and in talking to Mary Nichols, Mary is, you know,
21 very optimistic on the need for hydrogen as a transportation
22 fuel. And god bless, this could help there, I think, in
23 terms of looking at some of the economics, certainly, if you
24 had a power-to-gas commercial scale operating in California
25 today, you're not going to get, you know, 24/7 cheap power.

1 You know, you're -- I mean, the last thing I think
2 you want to do is take natural gas and run it through, you
3 know, to produce the power to then go out to power-to-gas.
4 You know, over time that would be more. So, you know, you
5 could be looking at phenomenally low load factors initially,
6 growing over time. And again, for something that's
7 relatively capital intensive, you know, you get back to
8 how's that economics look, you know? And again, I think as
9 you look more at the transportation sector than presumably
10 you look on fuel -- you know, there's a whole variety of
11 potential revenue streams that you may be able to tap into,
12 you may not, but again, I think just trying to start pushing
13 the envelope of what could be done there.

14 But again I think, you know, Andrew's raised the
15 other question of where's thermal storage? And, my god, we
16 can't even get thermal storage going, much less, you know,
17 how do you get to the power-to-gas side of it?

18 MR. BARKER: Thank you very much --

19 CHAIR WEISENMILLER: Well, thank you.

20 MR. BARKER: -- for this panel at the end of the
21 day. Thanks, folks, for sticking around.

22 And I believe we will move into public comment.

23 MS. RAITT: Did we get any blue cards? No? I
24 don't know if anyone in the room wanted to make comments?
25 Go ahead and go to the podium and identify yourself please.

1 MR. BRITTAIN: Hi. My name is Tom Brittain. I'm
2 a Mechanical Engineer for Black and Veatch. I've worked in
3 electricity for about 39 years, and 21 of that has been --
4 or 28 years of that has been in the hydro business. And
5 I've been able to work in most of the major utilities in
6 this state, and the electric utilities, and I find them all
7 to be very competent at what they do. And there's a
8 generally recognized need for this flexibility. And this
9 has been a very useful workshop for me to see what we're
10 doing. It's been a valuable process. And I think that you
11 guys really saw what was going to work and you saw some of
12 the things that you questioned very well, and I appreciate
13 that. Because there's a lot of great ideas out there and
14 you guys have heard a lot of them, and it was good to hear
15 those.

16 My concern is that most of these issues that were
17 brought up are basically hinging on how are we going to pay
18 for the flexibility that we need. And that's the thing that
19 is most important for all of them. And I would implore you
20 to focus on that because until we have a rate structure that
21 will recognize these things as the assets that they are,
22 they're not generating, they're grid enhancing or grid
23 assets, or however you want to do it, if California can't
24 come up with a rate structure, nobody can, because this
25 state is leading all this all this stuff. And that rate

1 structure is what's going to hold up everything. I mean,
2 Doug Devine mentioned four years to build the plant after he
3 gets past every last hurdle. And we need that plant in four
4 years because the direction the duck is going is that the
5 chest is about to hit the ground.

6 So I would just suggest that that's something --
7 become something that's your focus because you're the guys
8 that are going to make it happen, along, of course, with the
9 CPUC and Jerry Brown and everybody else. But you guys seem
10 to be on target. So I'm just going to encourage that little
11 approach, and keep doing what you're doing. Thank you.

12 CHAIR WEISENMILLER: Thanks. I guess, obviously
13 the question for you, and anyone else in the room or on the
14 line, is sort of in terms of what options did we miss, and,
15 you know, having sat through the conversation on the range
16 of options? You know, but again, some seem to be more at
17 the top of the list and some were at the bottom of the list,
18 and trying to, again, focus on the ones at the top of the
19 list that can, you know, provide some flexibility sooner.
20 But, yeah, the revenue is a huge question. And obviously
21 the market structure. Again, that's the en banc next week.
22 You know, but who signs -- you know, how do you get anyone
23 to sign long-term contracts. Thanks.

24 Come on up.

25 MR. CHANGUS: Good afternoon. Jonathan Changus

1 with the Northern California Power Agency. And I very much
2 appreciate the breadth of the topics discussed today. And I
3 think concisely, some takeaways and some thoughts is, you
4 know, starting off with very, as you noted, a very data-rich
5 presentation from the ISO, kind of about current conditions
6 and where we see some of the policies going.

7 But I would encourage us, as we look at 12 to 13
8 years down to the 2030 horizon, taking a look backwards 12
9 to 13 years and what were our assumptions then? And we
10 didn't have a duck curve. And we thought wind was going to
11 be the dominant renewable resource. We had once-through
12 cooling plants. We had 4,000-plus megawatts of nukes. And
13 all of that changed, not because we had poor planning in
14 2004-2005, but because unforeseen circumstances, policy
15 directions went a different place.

16 And so planning ahead to 2030, we already kind of
17 know some of the changes that we might anticipate based on
18 the policy objectives that have been established with
19 regards to zero emission vehicles, the 40 percent reduction
20 in GHG, and fuel substitution issues, we're trying to
21 decarbonize buildings; right? And so how does that change
22 the duck, as well, if we're successful in implementing those
23 beyond the 50 percent RPS? That's absolutely appropriate.
24 And I think we're going to see more of those conversations.
25 They're currently being held in other forums.

1 But with regard to the flexibility of the grid,
2 you know, there's going to be a lot of customer-facing
3 options, as well. And so we do a lot of technical work.
4 The distribution resource plan efforts at the CPUC is doing
5 a lot of kind of grid characterization, technology
6 characterization. But speaking with the Chair, sorry that
7 you've heard this before, there's a market piece, too.
8 There's the customer perspective. And I really appreciate
9 some of the middle conversations discussing that it's not
10 going to be a one size fits all. Time-of-use rates is going
11 to have mature. You're going to have those sophisticated
12 customers that are going to be interested in doing that.

13 And so I think part of what we're looking forward
14 to with regards to flexibility with the needs is that's
15 going to be, I think, challenging to do from a central
16 statewide bid, much the same as DRPs are going down more.
17 And there were some comments, and I'm sure this wasn't what
18 was meant about how local jurisdictions, you know, wouldn't
19 it be great if we could just -- it would be easier to
20 implement SB 350 from more of a single statewide approach.

21 And I would caution that, you know, actually
22 encouraging and working with the local jurisdictions, as the
23 guy that represents local jurisdictions, may actually be
24 more successful because we're going to be able to tailor
25 results to meet those customer interests as the evolve, as

1 those new technologies come out to satisfy kind of
2 decarbonization in the community level. And that might
3 actually be more effective than trying to squeeze things
4 into kind of statewide bids.

5 So a lot of comments there. I very much
6 appreciate it. I'm looking forward to kind of the evolution
7 of this conversation.

8 Thank you.

9 CHAIR WEISENMILLER: Thanks. Thanks for being
10 here.

11 Anyone else?

12 MS. RAITT: We do have two people on WebEx, if
13 there's no one else in the room.

14 CHAIR WEISENMILLER: Let's go to WebEx.

15 MS. RAITT: Okay. First, Nancy Rader, we'll go
16 ahead and open your line.

17 MS. RADER: Hi there. Good afternoon, Chairman,
18 Commissioners, and Mr. Doughty, if you're still there. This
19 is Nancy Rader with the California Wind Energy Association.

20 There's been a lot of good discussion today about
21 how we can deal with overgeneration and the related
22 reliability problems that we're starting to see. And they
23 are problems that cost money to solve. Listening today,
24 you'd almost go away thinking that overgeneration is a
25 blessing.

1 But a very important issue that I think has been
2 overlooked is what needs to be done to keep the problem from
3 keeping from getting worse and even harder to solve? I
4 mean, we're sort of assuming a lot of overgeneration. The
5 need for system flexibility is largely attributable to the
6 concentrated daytime production of solar energy,
7 diversifying the portfolio as we head to 50 percent
8 renewables, is going to be a lot cheaper than fixing the
9 problems that result from a lopsided solar-heavy portfolio.

10 The PUC, the CAISO and the utilities, they all
11 have said a showing that balancing the portfolio with wind
12 energy is the most cost effective way to avoid oversupply
13 and to reduce the need for flexible resources in the first
14 place. We heard from ERCOT today that, you know, they have
15 over three times the wind energy that we have here, and yet
16 the problems have been manageable there without the need for
17 storage or load demand response. So the primary focus
18 should really be on making sure we diversify the portfolio
19 to minimize the grid problems in the first place.

20 And even without CAISO expansion, which was
21 mentioned, if that's not in the cards right now, there's
22 still many ways to get the wind we need from the western
23 region. There was a lot of discussion about that in the
24 RETI 2.0 report. And I hope that you'll revisit that report
25 as you continue to think about the problem that you're

1 addressing in the workshop today.

2 And just lastly, I was glad to hear Chairman
3 Weisenmiller mention that we're -- that we've got existing
4 in-state wind resources at risk right now. Many 1980
5 vintage resources are struggling without long-term contracts
6 under very low CAISO market prices. And those prices will
7 not sustain the continued maintenance of these aging
8 facilities, let alone repowering them.

9 So given the long-term need for wind energy, this
10 is an ironic problem to have and one that needs attention,
11 primarily at the PUC.

12 Thank you very much.

13 CHAIR WEISENMILLER: Thanks.

14 MS. RAITT: Okay. Next is Ellen Bond.

15 Ellen, were you going to open your line? Go
16 ahead. Ellen, are you on mute or are you not there?

17 It sounds like she's not there, so I don't think
18 we have any more comments on WebEx. So with that, we could
19 probably just move on and just remind everybody that
20 comments are welcome and due on May 25th, and that's it.

21 CHAIR WEISENMILLER: Great. This meeting is
22 adjourned.

23 (The meeting adjourned at 4:58 p.m.)

24

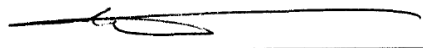
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