EFFICIENCY COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
2008 Order Instituting	)	Docket No.
Informational Proceeding	)	08-DR-01
and Rulemaking on	)	
Load Management Standards	)	
________________________________	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 10, 2008

10:00 A.M.

ORIGINAL

Reported by:
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David Hungerford, PhD

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ALSO PRESENT

Phil Pettingill, California Independent System Operator (CAISO)

Ahmad Faruqui, PhD, The Brattle Group

Barbara Barkovich, PhD, representing California Large Energy Consumers Association (CLECA)

Bob Benjamin, California Public Utilities Commission, Energy Division

Edward Fong, San Diego Gas & Electric (SDG&E)

Andrew Bell, Pacific Gas & Electric (PG&E)

Russell D. Garwacki, Southern California Edison (SCE)

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George Z. Chen, City of Los Angeles, Department of Water and Power (LADWP)

Stephen H. Badgett, City of Riverside, representing Southern California Public Power Authority (SCPPA)

Mike Pretto, Silicon Valley Power, City of Santa Clara, representing NCPA

Lon W. House, PhD, on behalf of the Association of California Water Agencies (ACWA)

Jeffrey A. Nahijian, JBS Energy, Inc., on behalf The Utility Reform Network (TURN)

Bill Roberts, Economic Sciences Corporation representing Building Owners and Managers Association of California (BOMA)

Rebecca Lee, Division of Ratepayer Advocates (DRA)

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I N D E X

P R O C E E D I N G S

10:05 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning, thank you all for being here. This is the Energy Commission's Efficiency Committee Workshop on Load Management Standards. I appreciate everybody being here today to work with us on this.

We have a joint committee with myself and Commissioner Rosenfeld representing the Energy Commission's Efficiency Committee. We are going to be joined shortly by Commissioner Chong from the Public Utilities Commission. I understand she is at a meeting across the street and will be here as soon as she is available. With us at the moment is Andy Campbell, her advisor.

Today we are going to look at one chunk of the load management standards authority and that is specifically rate design. Rate design, I think as we all know, is one of the key elements to having demand response happen through load management.

We have a number of reasons why we haven't had a very effective rate design program in California. I think we all kind of know that and have lived with that history. But this is an opportunity to move beyond the history and talk about what needs to be done with rate design to affect load management.

We all know that there are constraints with the legislation. AB 1X stands in the way of what we would like to be doing in rate design.

But I want to encourage people today to sort of think beyond AB 1X, recognizing that we do have some opportunities. AB 1X is here now, we have to deal with it, but it may not be here forever. And even as it is here, what else can we do? So I really don't think that you are serving the Committee all that well by suggesting there is nothing we can do now. In fact there are probably a number of things we could do.

Most people are probably cognizant of the fact that, gee, the Energy Commission really has no authority to do rate design, why are they bothering to hold a workshop on it. And it really is because this is a collaborative effort with our partners at the Public Utilities Commission. Commissioner Chong, who is the lead there on demand response, has been integrally involved in the proceeding with us. And we have the responsibility, I would say, to provide some input and provide our insights to Commissioner Chong, and through her to the Public Utilities Commission, on rate design for demand response.

So my only last observation is that we have a lot to cover. There's a lot of good information represented by people sitting in this room and I think that we will hear over the next several hours. So I am going to suggest that you really focus your attention on the rate design elements that we are here to talk about.

There are a number of other interesting, meaty, load management or demand response subjects I think people always love to talk about. But let's try to focus the day on the rate design issues.

With that, Commissioner Rosenfeld, any opening comments.

ASSOCIATE MEMBER ROSENFELD: No. Welcome.

PRESIDING MEMBER PFANNENSTIEL: All right, let's turn it over to Mr. Hungerford. David.

DR. HUNGERFORD: Hello. Thanks everyone for coming. I am David Hungerford of the Energy

Commission. I am the staff lead for demand response.

A couple of logistic issues before we get going. The exits to this room are on both sides of the glass behind you. The bathrooms are just across the hall from that glass. In the event of a fire alarm we ask that you take the exit and go out the door to your left, which is alarmed, and gather in the park across the street. There is a snack shop on the second floor, up the main staircase in the middle. You can go there with your green visitor badges without checking in any further.

So with that, let me do a brief background. I'm learning a new trick with software. All right.

Many of you who have attended the previous workshops have seen some of these slides before so I'll through them fairly quickly.

The load management standards here at the Energy Commission are being conducted under the order instituting rulemaking approved in January and the docket number is on the screen. Any documents you want to file for consideration by the Commission should be filed under that docket.

The purpose is to assess which rates, tariffs, equipment, software and other measures would be most effective in achieving demand response and adopting regulations and taking other appropriate actions to achieve a responsive electricity market.

The purpose of these proceedings is to obtain public input, explore the potential of peak load reduction and explore the coordination of regulatory authority between the Public Utilities Commission, the Independent System Operator and other entities.

The workshop schedule. You can see we are moving towards halfway through the workshop schedule. Today is the June 10 workshop on rate design. Comments from this workshop will be due on June 17. On June 19 there will be a workshop on enabling technologies and communications. On July 10, a workshop on customer education and needs.

The objectives of today's meeting are to discuss the principles of cost-based rate-making and general rate design considerations. Discuss the integration of retail programs and tariffs with wholesale energy markets. Explore how time of use and dynamic rates might benefit California. Review recent demand response and dynamic rate design efforts at the CPUC.

Discuss utility efforts, including public utility efforts, to develop time of use and dynamic rates. Discuss logistical issues and the implementation of these rates. And obtain further public input on the potential use of the Energy Commission's load management authority to move dynamic rate designs forward.

With that I am going to invite Phil Pettingill from the California Independent System Operator to join us for his presentation on wholesale energy markets.

MR. PETTINGILL: Thank you, Dave. Good morning Commissioners and others in the room here.

When I started thinking about how to address you here this morning and some of the topics to try to cover I thought what I would try to do here is to speak mostly about the roles of demand response in wholesale markets and maybe some potential points for you to consider in how to make wholesale rate design.

As you know, the California Independent

System Operator, we are primarily operating the grid and the energy markets. And so with that I thought I would cover about three, sort of broad areas. Why from our perspective the focus on demand resources. And I will use the term demand resources because I think a lot of time when we talk about demand response historically that term has been used for demand reduction.

But I am going to share with you a couple of points in my presentation about what may be very helpful is to talk about how to shift demand. So that it may look like a reduction in some points of time and a relative increase in other points of time as we try to balance the system on the large, integrated grid.

The second piece I thought I would talk about is just a quick overview of the wholesale markets. What are the key time lines and points in time for demand resources to participate in those markets, get their value identified and be available for reliable system operations.

And then finally go into some of the benefits that we see. Just a few thoughts on how demand resources can help. And I have got a couple of examples to try to walk through with you.

So first of all just why the focus? Well first of all I was thinking about how back in the Energy Policy Act of 2005 Congress had ordered that, at least for us specifically, that we eliminate any unnecessary barriers. And certainly the ISO is working very hard to try to do that.

We have taken some specific steps in our MRTU design, initial release and subsequent releases, to try to make sure that we can incorporate demand resources into the markets. And treat them, as much as possible, as we would any other generating resource to help us reliably operate the system. Certainly some of the benefits are, and as Congress had envisioned, to look at time-based resources and the necessary technologies in order to take full advantage of these kinds of assets.

FERC followed up more recently with an Order 890. And the reason why I mention that for your benefit is Order 890 actually focused on transmission planning, and transmission planning standards and processes at the ISO. But it was clear that FERC also intended us to fully consider demand resources in those planning activities. To not generally ignore them as has been done in the past but consider them as a valid resource in determining how to expand the transmission system.

And then finally our own Energy Action Plan here in the state focusing on energy efficiency and demand response as the preferred means to meeting new load growth.

But the challenge I think, is how we do that. And certainly the loading order puts DR very high. But the challenge is to try to make sure that there are available and suitable substitutes for the other resources that they would conceivably displace.

We also think about the technologies, the AMI initiatives going on in the state are extremely critical. We are certainly spending billions of dollars on these assets and we want to make sure that they effectively integrate, or allow us to integrate, demand resources most effectively.

I have already mentioned that when we look at the ISO's MRTU design we have certainly taken specific steps to give demand resources equal treatment and consider them in our dispatch, as well as how to value them and price them.

So with that let me talk a little bit about the MRTU time line, as I've mentioned. There's a number of things that are happening every day. I think what is critical when we think about demand resources is when do they need to be available. When do they need to show up in wholesale markets. Our markets basically close in terms of inputs to the market at ten o'clock.

The day ahead process internal to the ISO starts at that time and there's a number of key things that we are doing. Most importantly is we are evaluating all the bids that were received. We are then considering whether any of those bids had any market power and if so we are mitigating those bids and adjusting them.

But then finally we are running our integrated forward market. And what the integrated forward market will do is determine how to balance the supply resources that are provided to the demand that was bid in. And in addition to that we anticipate procuring 100 percent of our ancillary services during that step in the process.

I think the next step is critical when you think about what is happening with demand resources. Because RUC, or residual unit commitment, is a step in which the ISO looks at the demand that was bid in, the amount of load that was expected to be served, and whether that's consistent with our operator role and how much load we anticipate will exist in the next day. And if we find a difference the RUC is intended for us to procure additional capacity.

I think what is important here then is for demand resources to become apparent to us. So that in the event they are expected to be utilized in the following day the ISO would not otherwise commit or start units under the RUC process. Which certainly can be fairly expensive. And in this case what would be talked about on a day-by-day basis is capacity that had already been bought and paid for under a demand response program now is ultimately going to pay again, at least the start-up costs for RUC resources.

Now finally, the results of this whole market process then get published at one o'clock. So it is at this point where any of the resources become aware of whether we need them to serve load and operate the system in the following day. So this is the day ahead process.

But there's other opportunities. When we finish that day ahead then we move to an hour ahead process. What I have got here is an example of what would happen for operating hour from 10 to 11 o'clock. The key, I think, points on this slide are the opportunity to provide additional resources comes in up to 75 minutes prior to the operating hour, or T-minus 75.

And when we look at ten o'clock, that's going to be at 8:45 in the morning when we would expect to see bids or see demand resources become transparent to us so that we can consider them in the hourly dispatch or operation of the system. And at this point we can clear those resources at whatever the appropriate price is and compensate them for that shorter term identification and use during the operating day. So a couple of key points there on the day ahead and then the hour ahead in terms of time lines.

Let me transition now to why or how we can see some of the benefits, at least in the wholesale markets. And when I thought about this I was thinking, I think there's sort of three broad areas. First, what demand resources are able to do is help us reduce the load forecast and what our anticipated peak load is.

This then can give us, certainly, reliability services in operating the system, depending on how those products are designed. And certainly there's a wealth of opportunity for us to design different types of demand resources that can perform in different time frames and provide different services.

We certainly have a fair amount of energy response resources today. And there's still a place for energy response, emergency response-type assets in the future. We need to be careful about how they will play out in terms of market prices and the ability to operate the system reliably. Some of the economic issues that I raised earlier can be a problem, certainly with emergency response assets.

But most importantly, I think, is that we need to coordinate. We need to coordinate the demand response products and resources with the ISO markets in order to be able to fully realize their reliability and economic benefits. And let me share with you how that can happen.

First on the operational side. Clearly what demand resources can do is lower the number of resources that need to be committed. This is my RUC example we talked about a minute ago. And this can free up additional capacity for other purposes.

(Thereupon, PUC Commissioner Chong joined the meeting.)

MR. PETTINGILL: We are envisioning that with the introduction of large quantities of wind and other renewable types of resources we are going to need fast ramping and fast start-type resources to help with that integration. Reducing load can certainly free up those types of resources for that kind of integration service.

So clearly demand response can itself be very quick and responsive so that can help us with some of the reliability needs we have. The contingencies to respond to transmission emergencies, for example. If we know where the demand resource is at and it is in the proper location this can be extremely helpful in us responding to those kinds of transmission contingencies.

But more importantly I think what I would say is the reliability benefit is, rather than us having to do a broad, firm load shedding, we now have controlled load shedding. We know which customers, where and under what circumstance to use that resource. And so well-defined demand response programs can certainly be very effective in reliably operating the system.

If we take a look then at some of the market benefits that would come from integrating demand resources. Again, thinking about this in the two broad areas. There's certainly a load forecast and a peak demand reduction if known in the day-ahead and even in the hour-ahead. But the day-ahead process is where we reduce those start-up and minimum load costs coming out of the RUC. But it also will help us respond in the day-ahead and in the hour-ahead to a notion called scarcity pricing.

And I wanted to just take a minute and share this with you. One of the elements of the MRTU design that FERC has ordered us to add is the concept of scarcity pricing. The concern here is that prices do not necessarily rise when the system operator is experiencing a shortage in operating or other capacity reserves.

And so this will be a hard trigger that when we get to certain levels of operating reserves prices will automatically rise. This is an ideal place for demand response to become available to us, either before or during these conditions, and help avoid raising capacity prices across the whole system.

From a reliability standpoint, certainly having more competitive resources in the day-ahead and real time can significantly reduce prices in our day-ahead and real time dispatch. And these can help us prevent the undesirable economic impacts. What we need to do is we need to take care that those are not out of market actions. We need to try to, from the wholesale standpoint, see those actions taken in the marketplace.

Let me point out, I think, a couple of thoughts about where we might target some of the resources and where to get some of the greatest potential value. If we take a look back in the summer of just last year, 2007, what I thought I would share with you is we had a peak load of about 48,400 megawatts. And the top five percent of that peak load -- First of all, just for those that aren't familiar with this graph let me just orient you a little bit.

This is a load duration curve. And what

it is showing on the left hand side is very few hours do we get to these peak loads. If we look on the right hand side we are seeing we use 25 or 30 thousand megawatts capacity most of the time throughout the whole year. And so the point here is the top five percent of capacity, or in other words, 2,425 megawatts, is really only needed for 15 hours out of the year. Or at least it was during the summer of 2007.

So when we start trying to design programs that could be helpful, either economically or from a reliability standpoint, we are not talking about a large quantity of capacity. This is 2,400 megawatts out of a 50,000 megawatt system and it is required for 15 or so hours.

So if we take this same example when we look at what happened during our all-time system peak in 2006 and the parameters are very much the same. While the peak was higher at 50,000 that top five percent is now 2,500 megawatts and it's duration is 20 hours. And so my point I think is that with 2,500 megawatts being available for 20 hours or so we are able to save five percent of the installed capacity that would be necessary in the system by utilizing the demand resources that we already have available to us.

The other key piece that I'd share with you is how can demand resources help with integration. And I mentioned earlier that it's probably a time shifting case in point. Let's go back again to July 2006. And from this graphic here what I am showing you is the red dots indicate what was the wind generation at the peak.

And with something well over 2,000 megawatts of installed capacity there are needs -- very hot and peak load days, the resources got up to in many cases 1,000 or 800 megawatts of output. But that output was many hours after the peak occurred. And what we can see is their output during the peak was in the range of 200 to 250 megawatts.

Now the benefit here is, what happens to us operationally is now you can see how quickly these resources ramp up. They go from what is a relatively low output near the peak to a relatively high output. Two or three times the amount of output from these resources. And the ISO is going to need to try to respond to that by having fast ramping resources that can go down at the time the wind is injecting its energy to the system.

Where demand can be of great assistance is during the peak to reduce its consumption. And that will help because the wind resources are actually not producing. On the other hand if load can increase its use or shift so we have more load literally a few hours later that load can help absorb the energy that is coming from the wind resources.

So these kinds of operational realities are places where demand response or demand resources -- As I said at the opening of my presentation, in some cases we are talking about reduction, in some cases we are talking about increases or time shifting of the same demand. And if we can do that it can be a significant help in terms of operating the system. And the demand resource as a capacity resource is now providing more value to the consumers of California.

So let me, let me summarize with these key points. Integrating demand response into the wholesale markets is really a key, not only for reliability but also economics. We need to treat the demand and supply resources comparably. And if we do so, demand resources can compete very effectively from our perspective.

To do that we are going to need to reduce the barriers. This does require new tools, new assets like the advanced metering initiatives.

And we are going to need to be able to, in our belief, have access to a diverse set of participants. This means really all consumers, all loads. Being able to identify their interests in participating in the variety of demand resource products that we believe will eventually come out of this time that we are in.

In doing so we can provide, the ISO can certainly provide large and very liquid markets for the diverse set of demand resources.

But most importantly I think what is essential is to provide the price transparency so that the demand products can be properly valued. And we can grow those products where they are providing the best value, either economically or from a reliability standpoint.

So let me stop there and say, any questions?

PRESIDING MEMBER PFANNENSTIEL: Thank you, Phil, interesting. Any questions from the dais? Yes, Andy.

CPUC ADVISOR CAMPBELL: A couple of questions. The ISO, PUC and CEC are working together on a series of working groups that are focused on coordination of demand response between the retail and wholesale side. Can you speak a little bit to those activities and kind of the status of those activities.

MR. PETTINGILL: Well, Andy, I haven't been involved in the details of it. There are five different work groups; we have been involved in all of them. I think one of the key groups that we have wanted to make sure we participate in is the vision. Where is the vision for California. And I know the PUC has led that particular work group.

Two of the other groups, though, focused on how to integrate demand response into MRTU and I touched on some of the results of that. That we have been very effective in making those changes. We have a policy initiative that is going to go to our board I think next month in July that would adopt the policy for demand resources in MRTU Release 1A. So it's a few months after we start MRTU.

What else? There was an infrastructure work group as well. And I understand that group is now starting to really take on and do some good work. Again, I don't know the details of that. And maybe you can help me. There's a fifth one I think I missed in there.

CPUC ADVISOR CAMPBELL: I believe the other one is product specification, something along those lines.

MR. PETTINGILL: Yes.

CPUC ADVISOR CAMPBELL: And there is actually a meeting this Thursday being held here at the CEC with a number of those working groups meeting.

MR. PETTINGILL: So from our perspective it has been very good work. And as I said, the vision is something that we think was very important. We think it is on the right track and it looks very, very good from our view.

CPUC ADVISOR CAMPBELL: Then another question. Thinking about dynamic pricing in particular and how dynamic rates could integrate with the ISO market. If a utility or other load-serving entity has customers that are on some type of dynamic rate, critical peak pricing, maybe something else, and they know that at certain prices those customers, some of that load would go away.

Under the MRTU day-ahead market would the utility then be able to put in, submit a schedule that is actually price-responsive schedule to indicate that if wholesale prices reach a certain level then they would not need to consume, buy as much energy?

MR. PETTINGILL: Well yes. I mean, that's the way the day-ahead market design functions that I was walking you through the time line. In terms of the details, load serving entities are giving us what they expect to be their load and a price curve on that load. How much are they willing to pay in clearing that day-ahead market to serve that load.

To the extent that a portion of their load is at a particular price point I would certainly expect that they can reflect that in that load curve as part of their day-ahead bidding process, yes.

PRESIDING MEMBER PFANNENSTIEL: That actually was going to be my question too. How much assurance will the ISO have on some of these price responsive programs? Clearly there is a difference if there is a program where there is a control and the utility can control the load at a certain price point. But if it is up to the customer to make certain actions based on price signals would the ISO treat that the same as a load control response?

MR. PETTINGILL: Yes, I think -- Thank you. I think what we are now teasing out is that some of these DR resource programs, products, whatever term we want to use, can actually be bid in and reflected in the markets. Some of them may not be. Certainly if they were price responsive load those are probably not going to be actually bid in. So now I think the real challenge is to be able to anticipate how those loads will actually respond.

I can share with you, for example, that in some of the demand response that we have today, when working with the IOUs we know that when we call those programs we are not going to get a one-for-one load reduction. It depends. We know that some aspects of those programs may be 90 percent response rate, some may only be 70 percent response rate. I think that is what we will have to do in certainly working with the IOUs.

But from the ISO perspective what we will do is learn that at different price points with so much of that price responsive demand in the market, how much of that actually gets reflected in the real time service of load. And that will help us then adjust what we do in clearing the day-ahead markets and RUC and those other activities that we take in trying to set up the capacity.

One of the things we have done now in the MRTU Release 1 is we have set up a mechanism where we can work with the IOUs given their existing programs that they're calling or they're dispatching and have them tell us whether they intend to trigger those programs in the following day. And by doing so we take that under consideration and adjust our dispatch and our unit commitment decisions in the day-ahead time frame.

So I do think there are some steps we can take that are more prescriptive. And my second example, in other cases it may be a little bit of just learning how to change the dispatch and the market clearing, depending on how much price responsive programs are in the marketplace.

PRESIDING MEMBER PFANNENSTIEL: Thank you. I think that's it, thank you very much.

MR. PETTINGILL: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Before we move to our next speaker I want to welcome Commissioner Chong and let her know that we have already said good things about our working relationship so we are glad that you are here.

CPUC COMMISSIONER CHONG: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Gabe.

MR. TAYLOR: Good morning. My name is Gabriel Taylor. I am the project manager for this proceeding. The technical lead, Dr. Hungerford over here, asked me to take over the computer operations to speed things up a little bit.

Welcome Commissioner Chong, thank you for joining us. We very much appreciate your participation. Would you like to make any opening comments or anything at this time?

CPUC COMMISSIONER CHONG: (Shook head to say no).

MR. TAYLOR: I would like to welcome Dr. Faruqui next.

DR. FARUQUI: Good morning. Thank you for inviting me to speak at this workshop. I spoke here, I believe, in the first workshop on these proceedings on the third of March and a few things have changed and several others have not changed. However what I have done in this presentation is tried to account for some of the activities that are happening around the country in a bit more detail.

We have been in touch with the ISOs and RTOs around the country. We have just been hired by FERC to do a state-by-state assessment of all 50 states in the United States of America. And of course that is a very comprehensive, one-year long project that will be starting soon so I don't have evidence from there.

But I have drawn upon studies in the other regions. And in particular, to give this more of a California focus, I have drawn upon some research that is currently being funded by the Demand Response Research Center, which of course is funded by the CEC, to show the kinds of illustrated rate designs that perhaps could be used to achieve either the five percent or the ten percent targets that the previous speaker was talking about.

So let's begin with a take on today's

demand response. This is more of a cultural slide than a technical slide but it has important ramifications for how we look at the future.

Demand response today is largely invoked, and again I am giving this a national perspective, when there are imminent brownouts or blackouts and the programs are triggered by a reliability trigger of some kind.

They are based largely on yesterday's conditions. By which I mean there is aging technology. The most widely deployed technology today in the mass markets in the US is direct load control. It has been around for 50 years. In many parts of the country those switches are aging. In many cases people have said that only 70 percent of the switches actually work.

There are concerns about how much do you have to pay in order to get that reduction in load. And there are people who are trying to cut back the amount of payments they make because they feel they have too many free riders. So there's all of those issues surrounding direct load control. Now that is being reborn in today's environment but that is where it is today.

The rate designs that we have by and

large are curtailable and interruptible rates that go back at least three decades. They were developed for a particular objective in mind and in many parts of the country they have actually morphed into becoming economic development rates. And so people didn't expect to be interrupted, they were just getting a discount. And so when the interruption suddenly arrived there was a lot of concern as to what was going on.

That's basically what we have by and large in the bulk of the demand response that you find mentioned if you look at the reports coming out of NERC, for example.

The customers are being paid cash for lowering peak usage against a baseline that, of course, by definition is unobserved. It can never be observed in the theoretical sense. So it has to be estimated and there you have a lot of statistical methodology coming in. Those are the kinds of issues that we have when we look at today's demand response.

So let's take a quick look at the state of play. This is by various regions in the country. Some of them are NERC regions and some of them are power pools. As you know, parts of the country have organized markets and parts do not so this is the entire country.

If you go to the very right of the chart you have a US summary there that is labeled as NERC. The two colors are, the blue color is interruptible demand and the brown or orange combination color is direct load control.

And so in certain regions like Florida, which is the FRCC, which is the highest bars that you see on the graph, sort of second over from the left, they have a direct load control paradise if you will, in terms of the magnitude of response. Hundreds of megawatts. In excess of 800 megawatts and so on. And that's why you have such a staggering number there. But in most other parts of the country, according to this inventory which is the 2007 NERC Summer Assessment, the action is really coming from interruptible and curtailable rates.

So as we look at tomorrow's demand response what are the likely changes that might occur? The first one is that it is likely to be price driven. There will be perhaps default dynamic pricing.

There will be digital technologies which will play a decisive role. We have already been talking about AMI and that is certainly happening.

In some conferences the new buzzword is now the Smart Grid. And of course nobody really knows what is the Smart Grid except that it is smart and it is a good thing to be smart.

What we have though, what we have going on is there are more possibilities opening up on the technology front. And by and large in terms of tangible evidence that is out there today, by way of enabling technologies we are still looking at programmable thermostats that communicate and energy management systems that can be automated and become DR capable.

So in one vision, according to who you talk to, demand response will no longer be an option but will become a condition of service.

So think of this as an artist's sketch. So when it becomes a condition of service the question is, what will be the shape of the prices that await us. And what I am going to show you is on the horizontal axis is there is Risk, which is the Variance in Price. Sometimes known as volatility from a customer perspective. And on the vertical axis is the reward the customers will get in order for accepting a more volatile, more dynamic, more real-time pricing product.

That's sort of the trade-off space. If people were not getting the reward nobody would take the high volatility. It's just like the 401k plan or the stock market plan or the mutual funds. The idea is the more risk you take the more reward you are going to get.

The question is, well, what are the points for the pricing spectrum here? So just to anchor our ideas I have decided to anchor it on the flat rate and the flat rate is our benchmark. We are going to measure deviations from the flat rate.

So all the way out there, right, is the planet Pluto. Which some people say is not a planet anymore but let's say it's the real time pricing planet here. So that's way out there. And that is certainly a goal that some of us would like to have. And that's a goal that some states already have accomplished. Georgia, much of the East Coast which has restructured markets, all of their large customers are automatically defaulted onto an hourly price.

And it is very volatile. They can get

the reward. If they don't like it they can opt out to other products that retailers are providing. Which could be hedge products, half-hedge, fully hedged, you know, caps and collars and all kinds of options are there. And so what we have is this is our rocket that is going to take us to that planet Pluto. So we have a whole spectrum here of possibilities.

The most commonly mentioned idea, the one that certainly is not new to anyone in this room I assume, is critical peak pricing. It is sort of a hybrid product. It says, there is some volatility, some risk transfer. And it could come in a day-ahead flavor or it could come in a day-of flavor. So you can make it more dynamic or less dynamic. There are variations that are possible. But by and large it is significantly a step in the direction of RTP.

And then you have all of these other options that are out there along the spectrum of possibilities. There is, of course, the inverted tier rate. That rate we have in about a third of the country today. Certainly in California that rate has, you might say, gone on steroids under AB 1X. We have more tier than we need.

But the point is that it does help provide some degree of price response. Not necessarily at the time you need it, which is the peak we are talking about, the five percent number or the ten percent number that you were talking about.

In the statewide pricing pilot we started out with everyone who was on an inverted tier rate and then we said, could we do some more by having CPP on top of that? And it showed very conclusively, yes, you could do a lot more. The number was 13 percent. For residential customers the rate was five times higher.

Then you have seasonal rates, you have time of use rates. And then you have the variable peak pricing rate or VPP, which is really a hybrid rate between a CPP rate and an RTP rate. What it does is, on the critical days, let's suppose we have 60 hours of critical peak pricing. On a regular CPP rate that number is fixed and is known ahead of time. But in a VPP rat that number varies on a real time basis. And so that gives it a little bit of real time character.

Some people call it occasional RTP. That rate was born in Connecticut. And it is being talked about there. I understand there are no customers on that rate today. But there is certainly an attempt to cajole and persuade customers to check it out. Okay.

So ultimately the issue is customer choice. Nobody wants to impose rates on customers that the customers don't want to have. They don't want to be put into just a single bucket. At least that is the idea of customer choice and market based pricing.

So the concept is, how best to enable choice. Well if the only rate that is offered out there is a rate that is always lower than any of the other dynamic pricing rates then there is a very low probability that anybody is going to migrate to any of those other rate designs. Even though there might be efficiency gains for society as a whole, for the utilities and even for the customers themselves, they will not test it.

So one idea is to anchor the rate design around some kind of a dynamic pricing rate that is perhaps halfway along the spectrum. Maybe a critical peak pricing rate or some variation of that. You make that the default rate, you know, in the years to come when education and technology has made it, you know, more acceptable to have default pricing that is dynamic in nature. To anchor over there and to let the customers then opt out to other rate designs that more suit their risk preferences and tolerance parameters.

A quick survey of some experiments. I think several of you have seen these slides so I am just going to put these up for all of two minutes. We have looked at 14 pricing experiments, including, of course, the ones in California. But looking at those in Australia, Canada and France as well as several other US states.

And the message is pretty clear. That even with simple, time of use pricing that is not dynamic, actually we were having a discussion just before the session began with Mark Martinez. Some people regard time of use pricing as dynamic. If you describe that as dynamic on a year-ahead basis, I guess it is dynamic. But certainly a year is a long time and it is a bit of a stretch. But Congress certainly didn't make it any easier. They used the term, time based pricing. Who ever heard of time based pricing? They created it. And I don't know why they created it but it includes time of use.

And so there is a lot of interest just in regular time of use and that's what I am showing you here. You have responses around five percent. PSE&G in New Jersey actually got above ten percent and I am still trying to find out how that happened. But most of the time you would expect numbers five percent or slightly lower, with a two-to-one peak to off-peak ratio on the time of use rate. This is for the mass market, by the way.

Then you bring in enabling technology like the smart thermostat. And interestingly, even with time of use rates you suddenly find the graphs are much higher. And that is to be expected because response is now automated. So every time there is a peak period that responsiveness kicks in. ADRS, of course, is the automated demand response pilot, which advances gateway technology. And that controlled more than just the air conditioner. And so you are getting those significant impacts from that particular technology.

So now we go to dynamic pricing. defined here as pricing that has a lag time of 24 hours or less, as opposed to 365 days or less. And so you have peak time rebates, you have critical peak pricing and you have critical peak pricing with technology.

By and large the story is technology boosts responsiveness whether you are looking at CPP or time of use. And the second part of the story is dynamic pricing introduces higher responsiveness than static pricing like time of use. And that is largely because the prices the customers see are so much higher. It is not the dynamic nature of the price, it is simply the fact that it is a higher price that brings about the higher response.

So let's take a quick look at some work that we have been performing in conjunction with several of you in the room under the auspices of the Demand Response Research Center on advanced rate designs.

Through the project we have developed illustrative rate designs that show the range of possibilities, by sector, across a range of deployment scenarios. This is meant to be entirely illustrated. And it is based on generic data that originally came from one company. And we are very grateful to SCE for having provided it. But it is generic in nature and is not intended to be any one company's rate designs.

So we constructed rate designs. There's a whole report on what they were. We don't have time to get into it in this brief presentation. Let me just tell you that the rate designs we looked at were the bookends on that pricing frontier I had shown you earlier.

There was real time pricing, there was time of use pricing, there was peak-time rebates and there were critical peak pricing rates that were overlaid on top of a time of use rate. The impacts you see in the left panel are for the residential class. You see that the numbers range from 170 megawatts to 2300 megawatts, depending on whether the rate is implemented on an optional basis or a default participation basis.

And then you have the present value of avoided cost showing over on the right side. Those are -- They also fall into a range which goes from .2 to 2.8 billion dollars in avoided costs. These are sort of California-wide numbers using illustrative data for one utility and just meant to show the range of possibilities.

Two points that are worth making here and this kind of provokes some interesting discussion. The first one is, as you would expect, dynamic pricing rates, like peak time rebates and CPP/TOU, have higher impacts than TOU rates.

But what was interesting was that the real time pricing rates had lower impacts. And the reason for that is it depends on how you design the real time price rate and depends on how you take the capacity value and spread it out. In the CPP and peak time rebates the capacity value of the CT is concentrated in those 60 hours. And that is not how it is done in the RTP rate.

In the RTP rate, of course we had to construct a simulation of what the wholesale market would look like California in the absence of the MRTU. So we looked at the data that existed back in the year 1999. And we looked at the production costing model that simulated what the conditions would be today if an RTP market was created. It just doesn't have those huge bursts of high costs that you see in the CPP or PTR rates. So actually it had a lower impact than the CPP, TOU or PTR rates.

We also looked at similar rate designs for the medium C&I class. The general message was still there, which is that the CPP/TOU rates produced the biggest impact and the RTP rates produced the lowest impact. Again, reflecting the price history that was put in there.

Then we have the large commercial class.

And we have finally the large industrial class. My purpose here is not to really get into the specific numbers, because we can talk about those at length perhaps off-line. But just to indicate that there are significant possibilities in California. And again, these are illustrative projections for the future. They haven't yet taken place.

If you were to take all of those sectors and just add them up and look at what would be the impacts if you were to have default pricing, CPP/time of use for residential and medium C&I customers, and default RTP. So that's kind of like one package. Then you get the upper bound, which is the seven percent of peak number.

And if you go with the other end of the spectrum, which is optional RTP for all customers you get the one percent of peak scenario down there. So that sort of brackets the possibilities. That's the graph in blue on the left side. And then, of course, on the right side is just the translation of that into avoided costs.

Similar assessments are being made around the country. Everybody is looking at demand response. What I have shown here, these are not the four census regions. Sometimes people think these are the four census regions. They are generally the four regions. The numbers come from either a large state, like in California that's the West. In the Northeast it is basically looking at ISO New England. The Midwest is PJM and the South is ERCOT.

So these numbers were developed through various planning studies. These are projections. The blue lines are showing the traditional demand response programs. So that's the direct load control and the curtailable interruptible rates. They will still be around. Nobody is going to eliminate them, they will just be modernized and upgraded. But what will happen is their trigger might change. Right now the trigger is a reliability trigger. Many people are thinking of changing the trigger so it could also be dispatched economically.

And then on the top are the dynamic pricing impacts. In most people's view, those have an economic trigger and that is true. But they could also serve a dual purpose, as some people have argued. They could also be used in a reliability context if the enabling technologies are included in them. So the hard and fast boundary between economic dispatch and reliability dispatch in the future might change and they might become sort of more translatable into each other.

Overall the kinds of numbers you are looking at here are in the 10 to 12 percent range. This is looking at the year 2030 so keep that in mind.

PRESIDING MEMBER PFANNENSTIEL: Ahmad, before we leave that I just wanted to make sure I understand. The potential was estimated through a variety of different studies. There is no one place to go back and see the assumptions for each of these, I assume.

DR. FARUQUI: That's correct. Right now what we have is a variety of studies with some variation in the approach, some variation in the data quality, if you will.

Now EPRI and the Edison Electric Institute are in the process of doing a study very similar to this. And I am a part of that as well. That project will have a report in September. And it will have a national assessment; it will also have four census regions.

It will not go down to the state-by-state level, which is what FERC will be doing. So there's a series of projects that are leading into each other.

PRESIDING MEMBER PFANNENSTIEL: Would you expect that the dynamic pricing assumption here, though, includes residential customers?

DR. FARUQUI: Yes, it does.

PRESIDING MEMBER PFANNENSTIEL: For each of the regions?

DR. FARUQUI: It includes all customer classes. So there is an assumption here about AMI coming into place at sort of the national level by the year 2030.

PRESIDING MEMBER PFANNENSTIEL: Okay.

DR. FARUQUI: And that's why I am calling them a potential estimate. They may not be realized. Without AMI the dynamic pricing portion will be severely at risk.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

DR. FARUQUI: All right. So this is actually a slide that I have been allowed by EPRI to share with the group here. This is the first early result from the EPRI-EEI project, a version of which was presented in April at an EEI conference. And what this shows is, at the national level what is the load forecast without demand response. That is the line at the very top. And then the line at the very bottom is the load forecast with demand response, using what people regard as likely or achievable potential estimates.

This is not a technical potential assessment. It is not even an economic potential assessment. It is what people think is likely, feasible and probable by the year 2030. So there is a total impact of 11 percent. A good chunk of which, or seven percent, is going to come from the traditional kinds of demand response programs. And if that is all we had then you would get seven percent in this projection. But if you can add to it the dynamic pricing program that I just talked about then we will get an additional four percent.

These numbers, as you know, reflect a series of assumptions. They are expert judgment. And in some cases you might question the expertise of the experts but that's what they are. They do reflect people's opinions and it is like more of a Delphi process.

Over time these numbers will get more refined and perhaps we will need another five years of validation to trust any of these numbers. But this reflects a lot of expert opinion, a lot of interviews, a lot of conversations around the country. And I would say, at least from an opinion perspective, it is probably a defensible number. It's a large number. Eleven percent is large at the national level. There's a lot of power plants that could be offset by the 11 percent.

So why do we have so much resistance? We have this line here from the famous futurist who passed away, Arthur C. Clarke. He was asked about his opinion on why do radical, new ideas always take so long to come to pass. He said, well, there's a lot of opposition. The first reaction is, it is completely impossible.

The second reaction is, it's possible but not worth doing. Or in our case, yeah, it works in California but doesn't work in the South, it doesn't work in the Midwest. Sometimes the reverse might be true. Real time pricing works in Georgia but doesn't work in California. It depends on which way you're in. It always at work somewhere else. And that's sort of the second.

And then the last one is, after the idea has been around for awhile it might be accepted. "I said it wa a good idea all along."

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ahmad. We have been doing this for a long time. Many of us have said it's been a good idea for 30 years now.

DR. FARUQUI: It is a growing club but it is growing very slowly.

PRESIDING MEMBER PFANNENSTIEL: Yes, very slowly.

ASSOCIATE MEMBER ROSENFELD: But I think most everybody in this room belongs to that club. It is not very elite anymore.

PRESIDING MEMBER PFANNENSTIEL: Relative to what, they are not sure. Questions?

ASSOCIATE MEMBER ROSENFELD: I have a very friendly question. When you drew that plot of the risk and the reward, the one with Pluto up at the upper right, you actually had the courage to give it a shape. It came up very fast at first, big rewards for a small change. Did you have something in mind when you gave it that shape? I would have just drawn a straight line.

DR. FARUQUI: Well yes. I resisted drawing a straight line because I think a straight line is a specification of a curve and I don't know what the curve is.

And so what I did was, you know, looking at the stock market and other items where you have the tradeoff, you typically see a frontier. There are diminishing returns. At some point you have to accept lower and lower returns for more and more volatility. That's sort of the generic idea of the curve.

Now it hasn't actually been empirically validated. So it's still an artist's sketch, if you will. But I tried to make the point that it is not a linear relationship. And it will become more difficult as you introduce more and more volatility. We will get perhaps less and less benefits from that.

ASSOCIATE MEMBER ROSENFELD: Good, thanks.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much.

DR. FARUQUI: Thank you.

MR. TAYLOR: Thank you very much, Dr. Faruqui. I would like to welcome Dr. Barbara Barkovich next to give us an overview of how rates are made.

DR. BARKOVICH: Good morning. You have obviously seen me before too.

PRESIDING MEMBER PFANNENSTIEL: Welcome, Barbara.

DR. BARKOVICH: Thank you. David and Gabe asked me just to go over some of the aspects of electric ratemaking that are relevant to considering the issues that you are interested in. And I have tried to cram a fair amount in here and I'll go through them briefly. But specifically he wanted me to address questions of -- a little bit about marginal costs and then the cost allocation process and rate design and the need to recover the revenue requirement that would be relevant to deciding what you could do with dynamic pricing.

And before I start I would like to put in a word for interruptible rate programs, which still have the highest, shall we say, bang for the buck, and the highest level of customer response of anything that is in California right now.

Okay. This is really basic. However, it is important to understand that there is something called a revenue requirement, which is the amount of revenue that the regulator determines that the utility needs to recover through its rates. Those rates, based on a forecast of sales in the case of California, for a future period.

And that includes capital assets, that go into something called a rate base, where they are allowed to earn a rate of return and are depreciated and are fundamentally reviewed every three years. There are some exceptions if there's a major project addition then it can be reviewed more frequently.

And then there are what are called expensed items, which are recovered without a return.

The revenue requirement. In particular, as I understand it, for the purpose of dynamic pricing you are looking at responding to what is going on in the generation market and therefore that is what I am going to focus on here.

The revenue requirement for utility owned generation, excluding fuel, is reviewed general rate cases every three years. So remember that what is serving the customers is a combination of utility assets, which are owned by the utilities, which have fuel and operating expenses. It is purchased power in a variety of forms. And then there's DWR, which is a special category of purchased power. So all that goes into the generation portfolio. Which is, if you will, what's providing both the kilowatt hours for the customer and also, if you will, in terms of a price signal, also is priced differently.

So the revenue requirement for utility-owned generation, most of which but not all of which is hydro or nuclear but there are some gas facilities in there, is reviewed every three years in a general rate case.

Another thing you are interested in in the context of AMI is utility metering and billing systems. They are generally reviewed in generated cases, which again would be every three years.

Except in the case of AMI where there were specific applications and those therefore have been approved as the applications have been filed and the Commission has reviewed them.

Separately there is another process for approving utility energy efficiency and demand response expenditures and those are subject to a three year cycle. And in fact utility demand response proposals for 2009 were filed last week and the energy efficiency ones will be filed in a couple of weeks.

Fuel and purchased power. The fuel and purchased power, exclusive of DWR, is reviewed in the annual Energy Resource Recovery Account cases. And the way those are set up is they are set up for a future year so the costs are forecasts and the sales are forecast. So for example, PG&E is shortly going to file, today or not, its ERRA for next year. Edison filed in August. They are both for next year.

They look at a forecast of the revenue requirement, which means they're assumptions about fuel costs and what have you. They're also forecasts of sales. That's how you get the average rate is the revenue requirement divided by sales.

Those revenues are subject to balancing account recovery with future adjustments. So what this means is, unlike general rate case expenses where you basically forecast the expenses for the three year period, or expenditures, and then, you know, they're recovered, there is an ERAM-type recovery. We can talk about that later.

But in the case of fuel and purchased power, both the sales and the costs are forecast and then there are balancing accounts. So that if the utility recovers more than or less than what its actual costs are there can be an adjustment. And that would mean, for example, if sales were lower because of demand response there would have to be an upward adjustment the next year to reflect the shortfall in revenue. Unless, and I'll talk about this more later, the costs went down proportionate to the drop in sales. Then they would obviously cancel each other out.

And if it turns out that because of this forecasting the actual utility revenues are more than five percent different from the forecast they can make what is called a trigger filing. And PG&E has indicated it is probably going to make a trigger filing shortly. I don't know if Edison will. And one of the factors undoubtedly is the increase in the cost of natural gas.

There are annual ex post reviews of past ERRA cases.

And separate from this there are proceedings to allocate DWR revenue requirements.

So I think it is important in terms of sending pricing signals for generation to understand that there are different costing rules for the different aspects of the utility generation portfolio that is serving customers.

Now that doesn't mean you can price on the basis of marginal costs. But just so you understand, it's broken up in different bins. It is not all considered together.

For the purpose of cost, allocation costs are functionalized, which means there are generation-related costs on the one hand and distribution-related costs on the other hand. And those are allocated separately. And the rate components are designed separated.

And then beyond those there are what we sort of refer to as non-bypassable charges. That is, that there are costs that are not considered to be either generation or distribution necessarily. And not only are the costs allocated differently but there are separate rate components. This is relevant when we get to the subject of rate design.

Cost allocation, like rate design, varies by service voltage. Sub-transmission customers don't use the distribution system on PG&E's case so they don't pay for it.

Losses vary by voltage. You both have transmission losses and you have transformer losses so you have to consider both kinds of losses. So rates will vary by voltage in those classes that have voltage distinctions.

And everything to do with transmission is taken care of by FERC and that includes designing the actual rates.

So cost allocation methodologies are adopted every three years in phase two of the general rate case. And then basically that methodology is applied to every rate change that takes place in the next three years.

What are the cost drivers? Let's start with one rule which can create problems when you are talking about real time pricing. And that is that the revenue that is recovered through the rates, even if the costs are allocated and the rates are designed based on marginal costs, is adjusted to meet the revenue requirement.

So if the marginal cost is less than the embedded cost, the embedded cost being the average cost, the rates have to be set greater than marginal cost to recover enough revenue, and vice versa. And I know some of you know this but I was asked to go through all the steps.

In addition, if the non-bypassable charges are recovered through volumetric rates, as they usually are, they have to be added to the revenue recovered through volumetric charges. And this is important because, as I say in the last bullet, the end result is if you try to set rates based on real time pricing there is going to have to be an adjustment compared to market prices in order to make sure the revenue requirement is recovered and to deal with these volumetric adders for non-bypassable charges.

So if you are going to set rates using real time pricing that is actually market prices, for example, from the day-ahead ISO market under MRTU, assuming that that's a substantial market, they are going to have to be adjusted because they are not going to recover the revenue requirement. Or you're going to have to recover that money some other way, either through demand charges or through customer charges or something else in order to set the rates.

PRESIDING MEMBER PFANNENSTIEL: But let's be clear, the rates themselves don't have to be adjusted at that time. They get adjusted in the next cycle of true-off, if you will, which is sometime into the future. And so the customer can see a pricing that you've set. And then if it over- or under-collects the revenue requirement it then gets trued-up at some later point.

DR. BARKOVICH: Indeed it does. And thank you, I'm going to address that. But the other thing to consider is, if you just said, let's set the energy charges for customers on a real time pricing tariff at the real time prices in the ISO day-ahead market. That could be wildly different from what was required to recover the revenue requirement, in one direction or the other.

And yes, there could be a true-up and that true-up could be substantial. And let's just say that true-up is upward. It could be a 20 percent or 50 percent increase in rates the next year, leading to more rate volatility. That's just the reality of the situation.

Again, the cost for allocation of generation capacity revenue are based on, tend to be based on a combustion turbine proxy, which may be net of forecast of the energy sales, the revenue from energy sales, which is called the gross margin.

Then those costs for time of use periods, which is what we do now, are allocated to time of use period in season using LOLE. Which means, most of them are allocated in the summer on-peak period, but not all of them.

The attribution of the energy-related revenue, which is basically the fuel and variable O&M costs, is done now on the basis of a forecast of forward energy prices, which could be made a year in advance or part of a year in advance. And then sometimes there's production simulation of market-clearing costs.

One of the issues that has been a problem in setting these rates has been what is the shape of the variation in energy prices in the forecast year for which you're setting the rates. As Ahmad mentioned and as has been done in several rate cases, the shaping has been done based on old PX prices because we don't have any day-ahead market prices to use. In its most recent general rate case filing Edison has actually done a production simulation, which is, you know, I think has got to be better than using PX prices that are ten years old.

But in the process we are using now the reality of the situation is that whatever we forecast as is being that shape and whatever actually is that shape could be very different.

Then there is a separate cost allocation for what we call non-bypassable charges. If some of them are generation-related each one has its own allocation. Some of them are equal cents, some of them are based on system average percentage changes. They are all controversial and they are all adders to the rates.

I am not going to talk to much about this because I think Bob Benjamin is going to talk about it. But the generation-related costs are recovered through demand and energy charges.

Demand charges only apply to larger

customers.

And then again the point I made, which is that rates are set to recover the pre-determined revenue requirement. Rate options are usually set to be revenue-neutral.

If customer usage patterns change, the utility will recover the revenue shortfall the next year unless the costs adjust precisely with usage, which will never happen.

That means that all else being equal, the rates would be higher the next year and vice versa. So there's a lag built in by definition.

Utilities do studies to do TOU periods. They have different TOUs. Different numbers of hours, different numbers of months.

They all have seasonal rates. They have time of use rates for larger customers and optional TOU rates for most if not all customers. Most of the classes have optional CPP rates. There is probably nothing new there. Rate design is affected by statute.

And that's not to say AB 1X, that's also the baseline legislation.

And there's CARE, which is for low-income customers.

So there are a variety of ways in which rates are affected. Even interruptible rates have some statutory basis.

This is really small but I wanted to put this and the next slide up just for people who are not necessarily used to looking at all the different components of these rates. So this is E-1, that's a basic PG&E residential rate. You see that there are increasing charges by tier for generation. There are increasing charges for distribution. And then there are all these other adjustments that are all usage.

So in the residential case because there are no demand charges, basically things are volumetric. There may be a minimum bill but for these purposes we're sort of focusing on the fact that if you were to look at the total rates that would be these things added up for the different tiers.

This is E-19. That's sort of a medium light and power schedule. And again, this is to see, so you can have this in the handouts, that there are different rates by voltage. And this just shows the different time of use periods, et cetera.

And then what the next two rate slides show is the demand rates by components. So the demand charges, you have a generation and a distribution on this page. And for the energy charges you have generation and distribution and all these different adjustment factors for, for the rates.

So that's what I was asked to talk about. I'm sorry if I bored anybody to tears. But that's just sort of an overview of what goes on in the rate design process. I'm ready to answer questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you Barbara. It was absolutely amazing that you could do the entire rate design course in 20 minutes. I am impressed. It took many of us 20 years to get that far.

(Laughter)

PRESIDING MEMBER PFANNENSTIEL: I just want to -- I am absolutely willing to agree with you and emphasize the fact that current rates are enormously complicated and there is nothing simple about it. Beyond the concept of what you can do with rate design. There is nothing simple about current rates, much less what we will look at in the future.

But I just want to emphasize one point, if you agree with this. Let me just ask you. Is there any, do you see any relationship between current rate design -- and let's start with residential for the moment, and cost? Future, projected, marginal, embedded. Any kind of variation of cost?

DR. BARKOVICH: Well residential is always the toughest class because of a combination of baseline, AB 1X and how they relate to historical numbers plus CARE so that the residential requirement is collected by residential rates.

But the cost of any given kilowatt hour, whether that is actually related to the rate that is being paid for, is pretty arbitrary given the fact that we got this increase in rate structure with the first two tiers frozen except for CSI. And that CARE customers can have from a 20 to a 40-plus percent discount because it really varies significantly among the utilities. So the answer is that schedule really doesn't provide much basis.

As far as the other rate schedules go,

you know, for the last many years -- I don't know if it is going to be true this year because marginal costs have really gone up. But for a lot of years we had a situation where marginal costs were less than average costs. And so we were increasing rates compared to the actual cost of service in order to collect the revenue requirement.

And because we were doing it by TOU period -- There is evidence if you look at the largest customer classes that with the time of use rates that when you get to 12 noon, in the case of PG&E and Edison, that the rates actually flatten out. I mean they don't. The actual usage does flatten out, it doesn't go up. That is sending some price signal. Is it a precise price signal, no. But at least there is clearly something being communicated. Because even the temperatures keep going up obviously the usage, on average, doesn't. So there is a signal there.

I mean, could we do better? Yes, I am sure we can do better. I think we have really two constraints here. One of the constraints, and it is a big constraint, is the need to recover the revenue requirement.

If you are trying to send a price signal to people that says, right now if you buy power it is costing X, you have got to figure out, one, what do you include in that X. Is it energy only? Does it include a portion of the capacity-related revenue requirement? Because we do have a separate capacity market here in California and it has separate costs.

And if you do, do you do it like in CPP rates or in some other way? If you go to real time pricing, you know, you are going to be obviously communicating a day-ahead pricing signal from MRTU but capacity portions could be separate.

So the issue is, what are you trying to communicate. And the other issue is how do you recover the revenue requirement.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

I guess I just wanted to emphasize that one of the arguments about moving to some kind of dynamic pricing is, well, how do you track costs. It would be really hard to send the right price signal. What I would like to point out is that we are not sending the right signal now in terms of cost.

And even if we end up with an

approximation of costs, which is I think as you point out for the large customers who do have a time of use rate, just an approximation of cost. It actually has benefits. It has demand response benefits. And it is certainly no worse than the current rate design.

I think that I am really urging us to think towards improvement if not perfection.

DR. BARKOVICH: Obviously perfection isn't possible. I am just going to throw out one other issue because you are going to hear it from the utilities this afternoon and that is revenue volatility. You know. They may require their revenue requirement by the time there is an adjustment the following year but there may be some variability and that causes them some heartburn. So I will leave it to them to talk about it.

There's certainly room for improvement. I don't think we can ever get it right. And one of the issues, and you can look at this in the rate design literature, is if you really want to send straightforward price signals that are, for example, based on the wholesale market, then, you know, you can do what they do in the Northeast and just basically charge people that amount. But you are going to have to recover all the other costs that are relevant to be recovered from this customer somewhere else.

PRESIDING MEMBER PFANNENSTIEL: You do. And I don't -- Clearly that has to happen and I think that alchemy of rate design is going to happen. But, you know, PURPA was passed in 1978 and it said, let's get rate design right. And I don't think we have made any real progress in that regard. Maybe now with the better instrumentation that we have we can take another stab at it. But thank you very much.

Are there other questions? No? Thank you, Barbara.

MR. TAYLOR: Thank you very much, Dr. Barkovich. Next up, our last presentation before lunch. I would like to welcome Bob Benjamin from the California Public Utilities Commission, Energy Division, to discuss an Overview of Existing and Proposed Rates Offered by California Investor-Owned Utilities.

MR. BENJAMIN: Good morning. I am going to give just a brief overview of the what of rates. We have been on a quick trip to Pluto so far that Ahmad Faruqui took us on and Barbara just ably covered a lot of the why of rate design. Why should rates be a certain way or follow certain structures. And I am going to talk about, in a way, the much more mundane issues of what do we have now? What are our rate structures and rates in place now.

And to start just with some slides that show some of the language from some PUC and PUC/CEC decisions. And again, policies that encourage dynamic pricing. And many of you are familiar with all of these decisions, I am not going to read through them. I will just note that the Energy Action Plan II aspired to make dynamic pricing tariffs available for all customers.

And then the update in 2008 reiterated that prior policy, that demand response is second in the loading order after energy efficiency, which I think we have already today.

The next slide, it has quotes from a few more, a few PUC decisions relating to -- that encouraged dynamic prices. The first one, the one in April of 2005 concluded that all bundled customers should receive time-bearing price signals. They should and we are trying to make that happen but we are not there yet.

There's a few more decisions cited here and again I am not going to read them. But I will just note the May 2006 mentioned in the first and second bullets ordered each utility to propose default, critical peak pricing rates for all eligible customers over 200 kilowatts of demand in their next rate design proceeding. We are beginning to see some fruits of that now.

So this just touches on, and I won't spend long on this because Barbara really mentioned a lot of these issues already or these points. Just that the different rate classes, residential, commercial and industrial, have different types of rates that are mandatory or voluntary for them. Basically TOU rates are mandatory for large customers and voluntary for other commercial/industrial and so forth down the line.

Noteworthy is that we did just adopt default critical peak price rates in the San Diego general rate case for customers over 20 kilowatts.

And the residential rates. Essentially multi-tiered increasing block rates that we have had for 20 or 30 years now are the default and are what are used by the lion's share of residential customers.

Noteworthy too though is that we did also, we adopted the last bullet. The Peak-time rebate program that San Diego proposed for residential and small commercial customers, Edison and PG&E have also proposed peak-time rebate programs. And it is essentially a rebate that is given to customers who have reduced their usage on called even days from the low, what their determined baseline usage is. Which is as Ahmad described, an attempt to predict in order to measure what their usage would have been on a similar day the day before or very recently.

I am going to skip this briefly and go on to the next slide and come back to that.

These are just a bar chart and numbers at the bottom. The three IOUs in California's industrial or large customer time of use energy rates. The word industrial needs quotes around it because it is not really a concept that is used. There is not a bright line separating our industrial and commercial. It's generally a size measure in the tariffs. Demand over a certain kilowatt size.

I doubt that you can read the numbers on the bottom on the slide but hopefully you can in the handouts. They're rounded some anyway. It's just to paint the general picture that TOU rates are similar but they are different between the three companies. And they are highest for all the companies in the on-peak period.

Edison and PG&E. The blue bar is PG&E, the red bar, the maroon bar is Edison. Don't have a winter on-peak period. They divide the winter into two periods, off-peak and mid-peak. San Diego does use all three periods. And their time of use rates.

Let me go back to just some of the features of critical peak pricing rates, how they work. I won't read them all. It is noteworthy that -- The first bullet says the critical peak pricing rates take effect when current conditions warrant, not just because it is an average summer afternoon. That's what makes these rates truly dynamic.

The second point is that although the critical peak pricing rates -- And by the way, these conditions or criteria that I put up here, these are using San Diego's default critical peak pricing schedule just adopted. The other utilities' proposals along these lines. I don't know in detail and probably differ in some respect.

But in the San Diego critical peak pricing rate just adopted and effective May 1 for their large customers. Unlike a lot of other proposed CPP rate schedules these rates will be charged -- critical peak event days will be called by the utility a variable number of times during the year.

They don't have a target number of events per year to readjust the target through the summer in order to try their best to hit the target. They have criteria in the tariff schedule that says when they will call it, as they're shown in the slide.

Temperature criteria and load criteria on the day before. If those conditions aren't met -- Let's say if they are met very few times in a summer San Diego will call very few critical peak events in that summer.

So in a way that makes this version of a critical peak pricing schedule even more dynamic. It is really tied to what is happening. Not right now, not yet next year and not on an average forecasted basis but tomorrow. What's the temperatures and loads like. So there are truly dynamics that are raised, that are in place there.

It remains to be seen if there is, of course, an opt-out revision. Time will tell how many customers stick with those rates. But they can save money on them if they -- They're designed to be revenue neutral. So some customers certainly will be able to save money on them.

We have seen this.

This is back to the actual rates under critical peak pricing schedules that are in place of the three IOUs. Basically the differences worth noting on the chart. Obviously on the far right, the two sets of bars to the far right are critical peak pricing event day rates.

Notice San Diego doesn't have two bars there, they only have one. Edison and PG&E have noon to 3 p.m. moderately high critical peak rates, 3 to 6 p.m., very high critical peak rates. San Diego has, let's just say very high critical peak rates during the entire on-peak period, which in their case is 11 a.m. to 6 p.m.

The other rates during the non-event

days on this schedule are slightly lower than the comparable period rates on the comparable time of use schedule, generally speaking. There is some discount built in to the rates for the other hours where the customers can benefit. That's one of the areas they can benefit.

The other area is in demand charges. I won't spend long on this because Barbara talked about this quite a bit, what they are. They are measured by peak demand of the customer. Measured during differing periods. I'll just go ahead to a slide that shows these. It's easier to see what some of these periods are.

These are the demand charges the three IOUs have for their largest customers. PG&E's E-20 schedule and Edison's TOU-8 schedule, San Diego's AL-TOU with the critical peak pricing commodity tariff. I forgot to mention PG&E's E-20 plus the critical peak overlay.

What to say about these. Well the one thing I think is worth noting. Generally the summer on-peak demand charges are higher than any others. Except you will notice in San Diego's case the green bar, the group of bars second from the right, their summer on-peak demand charge is actually lower than their all-hours demand charge. And I believe that reflects that they are recovering that portion of their costs in the actual volumetric event day rate. I would welcome San Diego's confirmation if that's the case.

But anyway, you notice that while their volumetric or cents per kilowatt hour rate for event days on peak was much higher than the other utilities, their demand charge is much lower than the other utilities. That's more of the give and take and the other benefit I alluded to for customers on that rate that can reduce usage in non-peak hours.

This is --

MR. FONG: I was going to go over this anyway when I was up. In the San Diego case there are really two different rates here. There's the AL/TOU, which is strictly a three period TOU rate with a demand charge, and there is a CPP rate. And the CPP rate has this unique portion to it. I was going to go over it so I'll go over it now.

We call it the capacity reservation charge. And the capacity reservation charge essentially allows the customer to hedge against the CPP. They can go ahead and select and pay for a certain capacity level and any usage above that capacity level they will pay the CPP rate. So the capacity reservation charge is essentially in place of what you think of as the on-peak demand charge. It recovers that part of it.

ADVISOR TUTT: And can you identify yourself for the record, please.

MR. FONG: Yes, this is Ed Fong from SDG&E.

MR. BENJAMIN: Just if I could ask you to go one step further down that path. Customers under your AL-TOU and your critical peak CPP-D commodity schedule, they do have the freedom to choose a zero kilowatts capacity reservation, correct?

MR. FONG: Yes.

MR. BENJAMIN: And so if they do that then they won't pay that $5.85 per kilowatts reservation charge.

MR. FONG: Let's take an example here. The way we have it arranged, if the customer does not make an affirmative decision, that is for whatever reason, it is just defaulted to CPP. Then they will default to a 50 percent, essentially, CRC. So we've looked at the previous historical usage, peak demand, then they go automatically 50 percent of that.

However, if the customer chooses, let's say a CRC that is relatively low for whatever reason, and they exceed that, that's when they'll pay, that's when they'll pay the CPP rate for the kilowatt hour --

MR. BENJAMIN: The volumetric rates on that exceeding amount of kilowatt hours.

MR. FONG: Yes, yes, that exceeds the CRC level.

MR. BENJAMIN: Right.

MR. FONG: That is exactly right.

MR. BENJAMIN: Thank you. That clarifies some points about those.

Well we have heard about AB 1X and the Public Utilities Code section that touch on, that require baseline rates or increasing block rates for -- there are at least two tiers of rates for California residential customers. I won't dwell on this. The law is there that AB 1X is embedded in the California Water Code, passed in 2001. That's enough said on that. I think everybody here is aware of it.

And then this is, you might say, a

result of some of those legal constraints. The way that has become the dominant rate structure for residential customers in California, and I think in a lot of states in the country, tiered rates. Notice again slight variations.

San Diego in their recently concluded general rate case eliminated Tier 5 and consolidated it with Tier 4 so that the rates for, you know, X kilowatts and above to infinite amounts are the Tier 4 rates shown in that green bar, the last green bar on the right. Whereas PG&E and Edison still have five tiers of residential rates.

I think we all know well that on the X axis there is no time dimension here. This is all a matter of how many kilowatts you have used during a month. The more you use the more you pay in stair steps. And the next month you start all over as if kilowatt hours suddenly got cheaper. That's how this rate structure works.

And I am going to go over this and come back to it in a second. Just the last slide. I'm not jumping to this because I think it is more important, I think in a way it's less. Because customer accounts or numbers of customers can give a somewhat misleading picture. What you don't see here are the raw numbers of customers. There are so many residential accounts that they tend to skew any measure of anything by customer accounts.

Likewise in the commercial sector there are an awful lot of small commercial accounts of small kilowatt demand. So while this chart sort of in the middle rows there on the commercial shows quite a bit of number of customer accounts or percentages of customer accounts on non-time of use rates, those tend to be the tiniest customers. And their usage is almost always smaller than the usage of the commercial customers on TOU rates. So I wouldn't reach too many heavy conclusions from this slide.

To me the more interesting picture is this slide that shows the megawatt hour sales by rate type for the three utilities. We had to make some somewhat arbitrary choices of how many buckets to put these in. What we chose is the tiny green slice starting at 12 noon is critical peak pricing/real time pricing.

Actually among these utilities I believe only Edison has a schedule they call RTP-II. It is not actually tied to a real time market. It is a temperature-driven set of rates that reflect Edison's generation costs as simulated in about nine different types of days with nine different temperatures. On the hottest days the rates are extremely high and the coolest and weekends they are very much lower.

So it is a sort of quasi-real time pricing rate. Those are grouped in with the critical peak pricing as the two sort of dynamic, the most dynamic, if you will, types of rates. And by some estimation the only dynamic rates, truly dynamic that are in place.

And as you see the green slide is pretty small still. It is larger in San Diego. San Diego numbers cannot reflect the default critical peak pricing rate because it just went into effect and there is no data on it yet. This is based on customers who voluntarily chose their critical peak pricing schedules that were in place already in 2007.

Basically time of use is a pretty big slice in all of the companies, smaller in San Diego. The residential, the orange slice on the left is huge in all of the cases. There's room for work on that slice I think we'd all agree. So yes, this slide , I think -- I wanted to conclude with this to say, who says rates can't be colorful. Thank you. (Laughter).

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions? None here.

Thanks Gabe. I think that that's the morning session. So what I am going to suggest, because we do have a long afternoon ahead of us, that we break now and come back in an hour. So we are back here at quarter of one and get going on the afternoon session.

Thank you.

(Whereupon, the lunch recess was taken.)

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AFTERNOON SESSION

PRESIDING MEMBER PFANNENSTIEL: I think we are ready. We are going to start with Andy Campbell from the PUC. If people would take their seats.

Andy. So Andy is going to talk about PG&E rate design.

CPUC ADVISOR CAMPBELL: I am going to discuss, focus on a proceeding that is currently ongoing at the PUC and focus really more on the future, the potential future of rate design.

Actually a proposed decision in this particular proceeding just mailed today so it is unlikely anyone has seen that yet. I think looking at my Blackberry it looks like it came out about noon. But in here you will see a summary of some of what is in that proposed decision. And here in this particular proceeding we are focused on PG&E specifically, although some of the principles would be applicable, could be applicable to the other utilities also.

First at a very high level, just to repeat, the PUC's policy with regards to dynamic pricing is to make dynamic pricing tariffs available for all customers.

And ticking off quickly some of the benefits of dynamic pricing.

Of course it can lower costs by linking retail rates with the wholesale market. It can lead to more economically efficient decision-making. It can lower peak demand potentially.

It can improve system reliability.

And then the last two I'll focus on a little more because they are probably not appreciated quite as much. Dynamic pricing can reduce greenhouse gas emissions. In California during a hot summer afternoon when demand is high, that is when the least efficient, natural gas-fired plants are operating. And dynamic pricing can communicate to customers that -- discourage customers from consuming electricity at those times when the high greenhouse gas emitting resources are operating.

Conversely, overnight the system is more dominated by non-emitting sources like wind and more significantly nuclear and hydro. So similarly dynamic pricing could, in effect, give customers a reason to consume less during those high GHG periods and consume more during periods when there are fewer, less greenhouse gas emissions.

And also there is the link to the smart grid, which we discussed in a prior workshop. Because we really can't have a smart grid with dumb rates. Dynamic pricing is really what ties consumers into the equation and can make consumers a part of, really a part of the grid in a more dynamic way.

ASSOCIATE MEMBER ROSENFELD: Andy.

CPUC ADVISOR CAMPBELL: Yes.

ASSOCIATE MEMBER ROSENFELD: Greenhouse gas emissions. These dirty peakers also are big emitters of criteria pollutants to, aren't they? Afternoon peakers. So you also help with pollution and smog and so on.

CPUC ADVISOR CAMPBELL: Yes, yes.

And now moving specifically on to the PG&E proceeding at the PUC. A proceeding was initiated to really kind of look forward a number of years. PG&E and the other utilities are just in the beginning stages of their advanced metering deployment. And in the case of PG&E by 2012, according to their current schedule, all their customers will have advanced meters. So in this proceeding we are really trying to look forward over that period of time and answer three principal questions.

First, what types of dynamic pricing rates should PG&E offer its customers. Second, when should PG&E offer each type of dynamic pricing rate to each customer class. And then third, how should the dynamic pricing tariffs be designed and integrated into PG&E's overall rate design? And we did not just focus on the large commercial and industrial customers. We actually looked at all customer classes.

The outcomes of this, which you can find in the proposed decision, one part of it is a dynamic pricing timetable. Which kind of goes through each customer class and when PG&E should propose rates for each customer class. And then also providing some general rate design guidance that PG&E will be required to follow in its future dynamic pricing rate proposals.

And here -- I think we, in the prior presentations, have discussed generally some of the rate types. I'll just hit a couple of key points, which a number of parties really emphasized in this proceeding.

One, critical peak pricing. Although it

is a dynamic price, is really an administratively set price and is intended to be a market proxy, although it is not necessarily tied to the market. Some would see that as a negative. On the other hand the advantage is the simplicity that goes with that. That it does not require having an operating, day-ahead market in order for a utility to offer a critical peak pricing rate.

Another potential negative is that critical peak pricing is primarily focused on summer afternoons. Usually the time period is fixed. And as I note, the issue that is important to the ISO, as they have highlighted in their presentation -- for example, looking at wind at other resources.

Often the time when the wholesale market is most strained may not be summer afternoons. So there is value to having demand response at other times. However, summer afternoon is when you would most likely be calling on peak generation. And there is sort of the countervailing consideration of creating a rate that is easy for customers to understand.

On real time pricing. As discussed in this proceeding we focused on it as being tied to day-ahead, hourly prices.

And as Barbara Barkovich touched upon, the rate design will likely be complex. Also it is going to depend on what the California electric market design is at that point in time. As Barbara noted, there is a wholesale energy market. There also is a bilateral capacity market. And there is a proceeding ongoing looking at the future of that market structure at the PUC.

Also considerations of whether direct access is open may or may not enter into this. So some of the key points. There's also utility on generation as well as third-party generation. There's some complexities there but we are confident that those can be worked through.

And then a couple of other rate types that are touched upon in this proceeding. One, time of use, which is not a dynamic rate but is better aligned with costs than a non-time variant rate.

Then the peak time rebate, which is really an incentive-based program that is intended to be compliant with AB 1X.

Now this slide is a summary of the time table. It is a very summary form and I will walk through pieces of this.

This is specifically for commercial and industrial default rates. To make clear, what the proposed decision would do is require PG&E to propose certain rates at certain points in time. The decision would not, itself, adopt those rates so there would be a future -- in each one of the cases there would be a future rate application in which issues would be kind of fully considered. The details of rate design would be worked through.

Now looking across the top are the years, 2008 to 2012. Which covers the period during which PG&E's AMI project will be rolled out.

On the left, C&I customers, commercial and industrial customers, and we broke them down into three groups. Large, which is the greater than 200 kW, medium, which is between 20 and 200 kW, and then small, what we call small commercial because these are commercial, not industrial, which are below 20 kW.

And just looking at the 2008 column to see where things are today. For the large C&I customers time of use is the default rate and then for the medium and small a flat rate. A non-time variant rate is the default rate.

And in the proposed timetable PG&E would be directed to propose a default, critical peak pricing rate for the large C&I that would be effective in 2010. The table shows TOU/CPP to make it clear that this critical peak pricing is on top of a time of use, a time of use structure.

And then medium C&I would be on the same timetable. However, with medium C&I they are getting meters under the AMI deployment plan. And what the proposed decision would provide that once a customer has had an advanced meter for 12 months then they will be defaulted to critical peak pricing beginning in 2010. So in 2010 there will presumably be a number of customers that receive meters in '08 and '09 that would go on to CPP. And then in 2011 you have another batch of customers and in 2012 another batch of customers.

For the small commercial the timetable lags by one year to provide more time, particularly for customer education. Customer education is important for all these classes, especially for small commercial. It's a large number of customers and they may be less kind of attuned to rate and energy use issues.

In parentheses on the timetable you will see starting in 2011 is real time pricing. In this case real time pricing offered as an optional rate. So PG&E would be directed to propose a real time pricing rate that would be available starting in 2011 and would be available for all customer classes.

And we also addressed agricultural customers. I am not going to put that table up. It is a relatively smaller customer group. But we didn't want to leave anyone out so they are also addressed in the proposed decision.

I think the only class we maybe didn't include was, I think there is a streetlight class. We did not do streetlights rates.

Now on to residential rates. The timetable doesn't have much to say about residential rates. The proceeding did not address legal interpretations of AB 1X.

And for the purposes of the timetable we assumed that dynamic pricing must be optional while AB 1X rate protections remain in place. The proposed decision doesn't make any affirmative conclusion that there is that limitation but that's an assumption that is taken.

If you look at the timetable you will see the default rate going all the way across is the tiered flat rate.

And then starting in 2010 PG&E has proposed as part of their advanced metering upgrade case to introduce peak time rebate beginning in 2010. And that would essentially be a default rate. It's actually kind of a no-lose kind of rate. The customer can receive an incentive for reducing relative to a baseline but they are not going to be penalized for failing to reduce their usage. They are going to have to pay for what they do use during that period. So it's a default in kind of a different sense.

And then in parentheses are the optional rates that are available. TOU is already available, time of use. Critical peak pricing is already available starting in 2008 for customer with advanced meters.

And then the proposed decision would require that PG&E propose an optional real time pricing rate for residential customers in 2011.

And then the other element looking beyond AB 1X. Which the decision doesn't take any position on when this would occur. But the timetable does require PG&E to file a proposal for default time of use with critical peak pricing 30 days after AB 1X rate protections end. And that rate would be effective within one year.

The primary purpose of having that requirement in there is to make sure that when AB 1X does go away that the PUC does fully evaluate residential rate design at that point in time. It is yet to be seen whether the Commission at that point in time, what a Commission at that point in time would want to do with regard to rate design. Whether the Commission would want to adopt critical peak pricing as a default rate.

But that is -- I feel like that was consistent with the direction the Commission would be interested in going today. And we really just want to set a point out there in time and we will investigate this. We don't want AB 1X to go away and then it takes a few more years before anyone gets around to reconsidering residential rate design.

And the other component of the proposed decision is a series of rate design principles. For the past five to ten years rate design proceedings at the PUC have been settled. Which means that the PUC has not focused on rate design policy. And we tried to change that to an extent in this proceeding and developed some basic principles that PG&E will be required to follow when proposing specific, dynamic pricing rates. I have four slides that will walk through some of the key principles.

As you will see they are fairly high-level principles in most cases. The first slide are some of the very basic ones. That rate design should promote economically efficient decision-making.

And that to promote economically efficient decision-making, rates should be based on marginal cost. That has been kicking around as a rate design policy principle for a long time. but I thought it important to reiterate that, particularly in the context of dynamic pricing.

And then also rates should also seek to provide stability, simplicity and customer choice.

And next, another principle that may seem obvious but actually can involve some complexities in rate design.

If a customer reduces its usage and

thereby reduces the utility's costs the customer should see a commensurate reduction in its bills. There are concerns by some of the customer representatives in this proceeding that in some cases because of the way the balancing accounts work and so forth that a customer may see a rate reduction in one time period, in a future time period they will end up seeing a rate increase. It is a fairly complex set of issues that really gets down into the rate design math so we kept it in the proposed decision at a very high level.

Also the dynamic pricing rates should allow a customer to choose how much of their load is subject to dynamic pricing. And this builds upon the idea -- It is consistent with the idea that San Diego Gas & Electric has proposed in their critical peak pricing rate, which the Commission adopted, which has a capacity reservation charge.

It is likely that for some number of large customers, in particular who they may be interested in dynamic pricing and having some of their usage exposed to dynamic pricing because they see opportunities to reduce their bills. However, they may not want all of their usage exposed to that dynamic pricing. As a principle a customer should have some opportunity to choose the level of, the level of exposure.

And then finally going back to the ISO's presentation earlier that utilities should bid expected demand reductions due to dynamic pricing into the ISO's day-ahead market. As Phil from the ISO pointed out, there will be a learning process there. The utilities would need to sort of learn and develop models and learn to kind of forecast what customers do in response to these rates.

The ISO would also need to be comfortable with what is going to happen in order to really incorporate that into the ISO market process so the ISO isn't purchasing supply resources in cases where demand is not going to be there because of dynamic pricing.

Now specifically focusing on critical peak pricing. First, the critical peak price should represent the marginal cost of capacity plus the marginal cost of energy during the critical peak period. That is generally consistent with the approach, as I understand it, that has been taken with the CPP rates.

Second, critical peak pricing rates

should not also have generation demand charges. This gets into some of the more nitty-gritty of the rate design.

But in the case of PG&E's current large customer CPP rate, the way that rate is structured, if a customer is on that rate they will face a critical peak price, which is a high price, during these critical peak periods, which will be at 12 or -- it's either 12 or 15 times each summer. And they may reduce their usage in response to those and save some money but they also will be paying a generation demand charge based on their highest demand during the month. The concept of a critical peak pricing rate is that the critical peak price is collecting the peak generation costs. So it seems redundant to have both a CPP rate and a generation demand charge.

A third. The utility should be able to call a variable number of events each year based on actual system conditions. A concern that a number of the customers have with the current critical peak rates is of a fixed number of calls per summer and that utility will call it that number of times irrespective of what system conditions are that summer. And so if it is a very hot summer and an extensive heat wave the utility may zip right through all those calls. A very mild summer, the utility is still going to call it the fixed number of times.

From a customer standpoint a concern they have, a number of customers have with the fact that the rate is administratively determined is that it doesn't really reflect what is going on in the market. So allowing a variable number of events would allow the rate to more closely track actual system conditions.

And then finally, the utilities should be able to call critical peak events any day of the week, year-round. Currently for PG&E, events can only be called on weekday, non-holiday weekdays. And as the ISO points out, there are other times when critical peak events occur when the system is strained.

Probabilities would say it is generally going to be on a weekday afternoon so practically speaking this might not make a difference. However there have been, during some of the recent heat waves, some holidays and weekends when peaks were set in some of the utility service territories. So it makes sense to have more, it felt like it made sense to have more flexibility in the rate design there.

And finally on --

ASSOCIATE MEMBER ROSENFELD: Andy, I think I am going to ask you a question.

CPUC ADVISOR CAMPBELL: Okay.

ASSOCIATE MEMBER ROSENFELD: This, to my mind, very significant. Can you go back to the slide you just had.

CPUC ADVISOR CAMPBELL: This, you mean?

ASSOCIATE MEMBER ROSENFELD: Yes. Utilities should be able to call a variable number of events every year. Is that something you worked out and PG&E has actually accepted? Is that a done deal?

CPUC ADVISOR CAMPBELL: No, PG&E has not accepted it. It is in the proposed decision. That is the approach SDG&E has taken in their rate design.

ASSOCIATE MEMBER ROSENFELD: Okay.

CPUC ADVISOR CAMPBELL: And then on real time pricing. Here the proposed decision doesn't do quite as much. I think there is a consensus that it is too early to really dive too deep into rate design, real time pricing rate design. And especially if the rate design is tied to the ISO's day-ahead hourly market because the day-ahead market is not operating yet. And there will definitely be some complexities in the rate design.

We do want to hit a couple of the -- We hit a couple of basic principles in the proposed decision. One, that the energy charge should be indexed to the ISO's day-ahead hourly market prices. The important pieces of that would be the day-ahead market, not the real time imbalanced market. That appeared to be a customer preference. To be able to have the prices a day ahead.

And then hourly as opposed to more granular. Because the market does operate even on smaller time increments than hourly. But hourly is a -- again, that's largely a customer convenience consideration.

And then you see the word indexed and that gets to some of the issues discussed during Barbara Barkovich's presentation that the rate may not be exactly the day-ahead hourly market prices. There may be some kind of adjustment made to that rate. But it is preliminary to make any determinations on how that would be done.

And then finally that the initially, day-ahead hourly market prices should be aggregated across PG&E's service territory. Because it is a notable market there's -- I forget how many, some hundreds of thousands of prices. For the purposes of the rate design it seems to make sense to aggregate those across PG&E's service territory.

However, as the market develops your locational prices should also be considered. The ISO would love to have demand actually responding kind of on a more granular, locational basis to address locational concerns too.

And that's the last slide. I'll just say once again this is a proposed decision that has gone out. That means the full Commission has not voted on it. It is out for 30 days of comment and review. It could be up for consideration on July 10 at a Commission meeting. So there will be opportunity for parties to file comments on it and the Commissioners will have their input too. But what I have gone through now is what is in the proposed decision that mailed today.

PRESIDING MEMBER PFANNENSTIEL: Excellent, thank you, Andy. Questions? Discussion of this proposed decision? Art.

ASSOCIATE MEMBER ROSENFELD: I have just a factual question for Andy. I probably should know this. But back to your slide nine, a couple of slides back. The critical peak price should represent the marginal cost of capacity plus the marginal cost of energy.

Can you give me a clue as to how relatively important the capacity part of the charge is. Because real time pricing, as I hear it talked about, always talks about the market price of energy at the time. And I don't know whether that is leaving out a big factor or a little factor.

CPUC ADVISOR CAMPBELL: In the context of a critical peak pricing rate the marginal cost of capacity is going to be far larger than the marginal cost of energy because you are putting all of the capacity costs into the critical peak periods. That is going to be the larger component of the cost. And, in general, there was a lot of discussion in the proceeding about, do the energy prices or will the energy prices in the ISO market reflect capacity costs?

I think the general view is they don't. Generators and utilities do transact a lot of value in the bilateral capacity market. And so looking at real time pricing that is an important set of issues that will need to be worked through. That the energy prices themselves don't reflect all of the value related to the buying and selling of electricity. That there are these capacity costs.

And those capacity costs would need to be incorporated into the rate in some way. So that could be done just by kind of a fixed-dollar per kilowatt hour adder across all time periods. You could also actually combine the critical peak pricing type of structure with the real time pricing structure and have actually kind of a critical peak period that reflects most of the capacity costs. But there's different approaches that could be taken.

ASSOCIATE MEMBER ROSENFELD: But I just wanted to bring out, and thank you, that there is a real big difference there between -- in real time pricing you said, once you take into account -- try again.

In critical peak pricing, you said once you take into account capacity charge. And I think that is very important. And in the typical real time pricing proposal it is not taken into account. Good, thank you.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Andy.

Now we are going to move into a couple of panel discussions. David or Gabe, did you anticipate that we would have all of the participants sitting up at the table --

DR. HUNGERFORD: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- or coming one at a time? Okay.

We have first the utility panel with PG&E, Edison, SDG&E, SMUD, LADWP, NCPA and SCPPA. Why don't you find places along this table up front.

DR. HUNGERFORD: All right. The purpose of this panel was to, was primarily to discuss the prospects, plans and implementation issues for dynamic rates from the utility perspective. And the utilities were --

We have an hour for this. The utilities were given the opportunity to prepare a short presentation but we want to focus the time mostly on discussion between the Commissioners and the different utility representatives. So we do have those presentations available and they can be used either right here at the beginning in a presentation format or we can just refer to them as references, which is how some of the representatives chose to do this.

I would like to start with Andrew over here on the far left side of the table and have you guys briefly introduce yourselves, where you are from and which utility you represent.

MR. BELL: I am Andrew Bell. I am a regulatory supervisor in the analysis and rates area at PG&E.

MR. GARWACKI: Russ Garwacki, manager of pricing design and research, Southern California Edison.

MR. FONG: I am Ed Fong. I am director of customer services at San Diego Gas and Electric.

MR. LANDON: Rob Landon. I am supervisor of rates at SMUD.

MR. CHEN: George Chen, rates manager, LADWP.

MR. BADGETT: Good afternoon, Steve Badgett. I am the deputy general manager of the City of Riverside Public Utilities and representing the Southern California Public Power Authority today.

MR. PRETTO: I am Mike Pretto. I am the division manager of market analysis and pricing at the City of Santa Clara, also known as Silicon Valley Power.

DR. HUNGERFORD: All right. And to help --

PRESIDING MEMBER PFANNENSTIEL: Excuse me. Mike, you are here for NCPA today?

MR. PRETTO: I am here for NCPA.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

DR. HUNGERFORD: And just to help the court reporter, if you guys would make sure to drop off a business card with the court reporter before you leave, when the panel is over, he'd appreciate that.

All right, let's see. I believe, Russ, you have a brief presentation to go over. Would you like to start with that or would you like to, would you like to defer?

MR. GARWACKI: I can start, that's fine.

DR. HUNGERFORD: All right.

MR. GARWACKI: I do have copies, 25 copies of that presentation here. I didn't put them in the front. The presentation has a lot more words than I'll go through. What I'll do is I'll hit on some of the highlights because we do only have an hour. Starting off with some general comments on dynamic pricing. If this is an eye chart, I apologize.

One of the reasons that we're here, obviously, is that dynamic pricing is essential to the efficient use of resources and pricing equity associated with capacity costs. And I'll talk a little bit about what that means on the next page in terms of volume of revenue requirement.

Our proposals. We currently have five active proceedings in front of the California Public Utilities Commission. We have got an outstanding SmartConnect application, AKA AMI, or we can throw a few more acronyms out of that there.

Our demand response, cost effectiveness rulemaking has been in place since January of '07. All the utilities are involved with that as well as the ISO is actively engaged in that rulemaking.

The demand response applications that the three utilities filed a week ago yesterday. I don't have a number on that one quite yet. But that represents the demand response programs for the period 2009 through 11.

And our GRC Phase 2 application, which Barbara Barkovich described. We have got a filing out there that we proposed in March of this year and then we are filing an update in about three weeks.

And then as well, it sounds like we have got a proposed decision on the dynamic pricing proceeding, which is coming out of PG&E's Phase 2, which Andrew Campbell just described in some detail.

Our proposals are consistent across all five of those proceedings. And it is important, obviously, that it is so. We don't want to get caught up in relitigating these issues time and again.

Some of the questions that came out in terms of what we wanted to cover this afternoon. Our proposals provide both a level of control and to increase the level of demand response.

We are proposing additional incentives,

a la San Diego, in that our programmable, controllable thermostats represent a linchpin of a lot of demand response, especially for our residential and small commercial customers. We have additional, and what we'll talk about in a couple of minutes, is additional peak time rebate credit amounts for those customers that are willing to participate in a programmable, controlled thermostat program.

Again, SCE believes that customer education and simplicity of design are essential to the acceptable and response of dynamic pricing.

Post-AB 1X, we talked a little bit about this. And that is, the future is a bit murky in terms of the post-AB 1X world. But again, we believe that dynamic pricing should be deployed on a voluntary basis to the residential customers.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, Russ.

MR. GARWACKI: Yes.

PRESIDING MEMBER PFANNENSTIEL: Why post-AB 1X on a voluntary basis? If it is on a voluntary basis, why not now?

MR. GARWACKI: Actually the voluntary rates are available now. And I guess that was a bit unclear. I guess I should have said, in a post-AB 1X world, to be more correct in wording, that the dynamic pricing should not be mandatory. That is probably a more correct wording.

PRESIDING MEMBER PFANNENSTIEL: How about default?

MR. GARWACKI: Default prices. We haven't reached a firm conclusion on that. I think if you have default pricing for four million customers I think it is going to be somewhat traumatic. And I think we'd have to sell that with the educational process. And I don't think we have reached a final conclusion on that.

PRESIDING MEMBER PFANNENSTIEL: Well let's back up then. On the voluntary process today, in an AB 1X world, you say you do have some dynamic rates on a voluntary basis available now, right?

MR. GARWACKI: Correct. And we are actually greatly expanding those in our Phase 2 application.

PRESIDING MEMBER PFANNENSTIEL: And is that, are you promoting them through, say, your roll-out of the advanced meter? Are you planning to combine the roll-out with the offering of those rates and the marketing of the rate?

MR. GARWACKI: Absolutely.

PRESIDING MEMBER PFANNENSTIEL: So that is part of the plan. So as every customer gets one of the advanced meters that customer will be marketed for participation into dynamic rates.

MR. GARWACKI: There will be advance notification that the customer will be getting their meter, and as they get their meter they will be marketed to. As the information is collected from the AMI meters, from the SmartConnect meters, we will be able to, we have got websites in progress where we will be able to identify which rate would be optimal for these customers and present that information to them as well. But this is a roll-out over a five year period, which isn't expected to conclude until 2012.

PRESIDING MEMBER PFANNENSTIEL: That's fine. All right, thanks.

ASSOCIATE MEMBER ROSENFELD: Wait, I would like to expand on that a little bit.

Chairman Pfannenstiel asked you about marketing time-dependant rates. Does that mean time of use only or does that mean time of use plus critical peak pricing? The extra ten days.

MR. GARWACKI: Well, we are going to be focusing on residential, I think, primarily, perhaps?

ASSOCIATE MEMBER ROSENFELD: Yes.

MR. GARWACKI: What we are looking at right now for our 2009 general rate case is as the meters are installed these customers will be on a peak time rebate program. Coincident with that the customers will also have the ability, should they so choose, to also either go on a time of use rate or a time of use rate with a critical peak pricing overlay as well. It is not mandatory at that point in time because the roll-out situation is long.

But the customers will -- All customers will be enrolled in the peak-time rebate program. If the customers so choose we will have, and we are filing, critical peak pricing as well as time of use offerings as well. So we have lots of options.

In terms of the next page, principles of cost-based ratemaking. Again, I am not going to go through this. Again, marginal cost pricing. I think the important point to notice on this chart is that capacity in our 2009 rate case represents about 18 percent of our total revenue requirement. And so when we start talking about how much, how much bill impacts there can be, even if we completely zero out that capacity revenue requirement, it is still represented at an 18 percent portion of the total bill.

AMI. Again the historical cost of high-function metering has dictated less-efficient rate designs. And that is what we are here to talk about.

One of the questions that was posed. The time of use rates generally are designed to be revenue-neutral to that class. And as customers respond to those costs, as Barbara mentioned, it is correspondingly offset by reductions in our costs. Our total revenue requirement goes down as opposed to just being shifted around or your deficiencies built up.

In terms of page four. Again, I think I mentioned I was just going to blast through some of these and just mention some of the high points. Page 4, in our Phase 2, capacity costs have gone up quite a bit since our 2006 GRC filing. Our current marginal costs show $119 per kW year and will be reflected in increased demand response incentives with our filing in a few weeks.

Our rate deployments. We are also under order to have default critical peak pricing for greater than 200 kW customers. Again, direct access and our base interruptible customers are among customers excluded from participation. So that's a fairly large chunk of customers.

SmartConnect enabled rates. Again, peak time rebate. Default TOU for C&I customers. Opt-in TOU available for all classes. Once you receive an AMI meter the sky is the limit on options.

Some of the logistical issues that bring up. Pricing inconsistencies. We have all kind of flogged AB 1X to death. I am not going to dwell on that. But I will also note, and as the ISO has mentioned several times, is how do we reconcile the differential. And that was emphasized in a ruling that went out last night in terms of, what is the quantification of system reliability programs that need to be maintained, et cetera. So that is an open issue. It doesn't need to be -- the issue is getting worked.

In terms of follow-up, in terms of backup slides. I also have a matrix that talks about, that shows what our current rate designs are by customer group, what we are proposing in our Phase 2 and what we envision in a post-AMI deployment world.

We talk about -- I mentioned a little bit of what our peak time rebate program market research is.

Give a little bit of customer rate group overview in terms of what percentage, what different rate groups are on time of use, what their coincidence is with system peak, et cetera.

And then also talk a little bit about the inequities associated with the AB 1X and what we are doing in our Phase 2 to try and mitigate that. But that's all as part of the backup.

That summarizes my five minute blast, summary of a couple of hundred pages of GRC testimony.

PRESIDING MEMBER PFANNENSTIEL: Good job, thank you.

DR. HUNGERFORD: Why don't we move on to San Diego Gas and Electric.

MR. FONG: Okay, thank you. I will also do the Russ act here and try to get through 30 years of dynamic pricing with SDG&E.

A couple of things. I know the next page will come up. I just want to reiterate that from the San Diego Gas and Electric side we are very grateful and appreciative of the Public Utilities Commission actually approving and authorizing the default dynamic rates for us in our GRC Phase 2. I think we believe that is the first step at this particular point in time.

This is nothing new for SDG&E. SDG&E actually was the first utility to have time of use rates for customers as low as 20 kW and above. And this was in the late 1980s that that occurred for, really, over 20,000 customers at that point.

We do believe in moving towards cost-based rates. And what we described and you have heard today, transparent pricing. And I'll put transparent in quotes. It is in the eye of the beholder what is transparent at this particular point.

From the statewide pricing pilot. I may have mentioned it a little bit this morning. One thing is quite clear. That essentially all customer classes do and should contribute to demand response. So we don't believe that we should exempt a customer class from demand response or dynamic rates.

And we also recognize the reality. The reality is that regulation, legislation, technology. They all evolve and we should be relatively flexible at this time as we look at policy, policy direction. And I'll describe it in one other slide. It is that we shouldn't be fixed on single point solutions. Single point solutions are good maybe for one point in time, not for another point in time.

I will not go over a lot of things that have already been gone over today because Andy Campbell and Mr. Benjamin have already talked about some of the things that SDG&E has done.

I will mention one thing on the peak time rebate. We really believe that that is a transition. It is a transition to whenever post-AB 1X occurs. And at that particular point for the residential and small business customers at some point you would really have to look at default dynamic rates for those customer classes.

What that form takes. That can be talked about, discussed, argued.

We understand that the peak time rebate is incentive-based rates. Our unique proposal there, and this was actually as part of our GRC Phase 2 decision. We have a two-tiered or two-stage peak time rebate, one at 75 cents per kilowatt hour reduction and another at $1.25 per kilowatt hour reduction for customers who have enabling technology. And this is to encourage customers to adopt, install, enabling technologies in their household.

For the small business customers we also have a peak time rebate. Today the small business customers are 20 kW or less and they are a flat rate. And ultimately, again, we see that as part of the transition after the installation of AMI meters to move to a default, dynamic rate of some form. And whether that takes the form of what I call a quasi-rate, like a TOU rate which is not pure dynamic, or some other rate that I think is yet to be decided.

On the next slide I talk about CPP. I won't dwell on that because that has already been discussed quite a bit. A couple of things to be said on CPP. When we talk about an opt-out rate and a default rate what it means is that if a customer makes no decision, does not make an affirmative decision, this is the rate they default to, a critical peak pricing rate.

In San Diego's case we allow the customer -- The CPP rates were effective May 1. The customers actually had 45 days after May 1 to make an opt-out decision. That is, to opt-out to the otherwise applicable rate. In this particular case for the overwhelming majority of the customers that were 200 kW or above it's a TOU rate, a three period TOU rate with a generation demand charge. So they have a 45 day window. Obviously that is coming to a close in the next few days.

I want to speak to a few things and this is some of the things that -- I look at Ahmad here. Some of the things that we discovered in the statewide pricing pilot. They are as true in the statewide pricing pilot and probably even more true today as you begin to look at the data. And this has to do with looking at the customer data.

What we discovered in the statewide pricing pilot. If you look at demand response it does vary by customer. Often you hear in all the demand response analyses, pilot projects, this thing called elasticity or demand elasticity. Elasticities vary.

And what we discovered in the statewide pricing pilot on the residential side is that 30 percent of the customers provided roughly 80 percent of the demand response. What does that tell you? That there is a dispersion or a distribution of elasticities across the residential customer base.

What that also tells us is that from the utilities' point of view and from the Commission's point of view, in terms of looking and targeting certain customers, we have to do much greater research in terms of how you customize particular programs and rates for particular customers and how you target the education there. And what we don't know, what we have not done and we don't know is to get down to a micro-level in terms of who this 30 percent is when you get down to that level of segmentation.

It is called, if you want to call it, the customer experience management. It's sort of the popular buzzword right now in the customer service area. Understand how you shape the customer experience. What particular programs and what we call bundle offers to the customer.

I'll add one final point here on how we

begin to educate the customer in what we provide. On this issue I was talking with Ahmad this morning. The question is, what kind of information, what is the cost of providing information to the customer. We have talked about education programs and how much we would invest there.

Well that's a blanket statement. You don't want to have one size fits all in terms of the education. In the billing envelope put an insert in there. That probably isn't the most effective way. This is the research that we will have to do. It is forthcoming. It is probably an investment that we have to make in customer research.

I will go on to the next slide. I think Dave Hungerford had asked us to look at sort of the challenges and barriers. These things are obvious, right? Infrastructure is a challenge and a barrier.

How fast we deploy the smart meters.

How the adoption and penetration rate of energy management technologies out there, what we think of as enabling technologies.

From the regulatory. I won't hark on

the AB 1X issues and what will be happening with the Cal-ISO. I won't hark on that.

The other thing I would add, though. It was brought up a little bit this morning by the Cal-ISO and this is -- On the environmental side when you look at renewables, as you enter in a greater and greater proportion of generation being renewables it actually makes demand response even more important. Because you have to balance now the ups and down for renewables. There's less reliability there. And that gives you what we call another policy instrument to have in your hand.

The last point that I would make here is the difficulty that I just heard Commissioner Rosenfeld bring up. What should this price signal be. And this is the complexity of the situation that has to be worked out with the policy makers here.

When you take a look at a real-time price, what we've heard, there are really three components that could enter in. Any/all, any or all of the three components. What we call short-run marginal costs, which is the energy price. Long-run marginal costs, which is avoided capacity. And something that we didn't hear today but that we have seen in proceedings, the social marginal cost, which is the environmental side, the environmental benefits.

I'll go to the very last slide here but not going through the bullet points. But I want to reiterate a few things here. I mentioned earlier in the introduction that everything is evolving. And we recognize that. We should all recognize that and we should be careful here or we end up fixing too much on what we think of as the optimal or unique solution.

And my word of caution. Although where SDG&E has been very aggressive in this arena it does not mean that the solution that we have today, even with our GRC Phase 2 solution, is a solution that we will have two years from now or three years from now.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ed.

ASSOCIATE MEMBER ROSENFELD: Ed, could I go back to a comment you made that I didn't, I just wasn't aware of. You talked about a May 1 decision, opt-out, and it's coming to a close. To what class was that offered?

MR. FONG: In this case particular case when I talk about the decision it was actually a decision in late March. It turned out that the first customers -- I'm sorry, it was late February or early March. The customers that were first impacted, the default dynamic rates are large customers 200 kW and greater on the commercial and industrial side. And effective May 1 the 200 kW customers with the appropriate metering and communications defaulted to CPP.

ASSOCIATE MEMBER ROSENFELD: Did you say how many of them are still there? They've got this, what, 45 day window?

MR. FONG: Yes. There is a 45 day window for most customers who defaulted May 1 to CPP to opt-out. We have seen very few opting out at this particular point.

ASSOCIATE MEMBER ROSENFELD: Inertia works.

MR. FONG: I think so. In many ways we have protected them. There is a one year bill protection and there is the CRC. So we have seen -- Actually the customers speak fairly intelligent at this point, looking at the capacity reservation charge. We have a tool out there for them to do a what-if analysis on the capacity reservation charge.

ASSOCIATE MEMBER ROSENFELD: Thanks.

MR. BELL: And you told me that a number of them have signed up for much more than the 50 percent.

ASSOCIATE MEMBER ROSENFELD: We can't hear you, Andrew.

MR. FONG: Andrew asked the question behind the scenes of how many have signed up for above the 50 percent default that we have for the CRC. And most of them have actually signed up for more than the 50 percent default capacity reservation charge.

PRESIDING MEMBER PFANNENSTIEL: And the same question that I asked on Edison. As you put in your advanced meters are you offering all the residential customers a time-bearing rate of some sort?

MR. FONG: Today we already had an optional, what is known as a DR, a residential TOU rate. I think we will probably end up thinking what other voluntary dynamic rates we will have. One thing that I saw from Andy Campbell's presentation is that he has laid -- and we didn't think of this -- a 12 month window, right, in terms of education. After you have deployed the meter there is a 12 month education for the small commercial customer and then you move them to whatever the dynamic rate is.

I think in this particular case, Chairperson Pfannenstiel, we want to think that through a little bit. The education period may be a 12 month period. I don't know what sort of option of dynamic rates we would offer. Right now we would just have the PTR. They will automatically -- We call it default but it isn't, it is just part of the -- it is just part of the residential rate offering, tier rate offering as PTR. You don't have to sign up for the peak time rebate, it automatically occurs on the bill.

PRESIDING MEMBER PFANNENSTIEL: Right. But the peak time rebate is not a dynamic rate as far as I am concerned, it is not a time bearing rate. It really has no price signals especially associated with it. So I am looking at one of the clearer kinds of time-bearing rates. Time of use is the kind of least attractive but basic kind.

MR. FONG: Yes.

PRESIDING MEMBER PFANNENSTIEL: And then

something even more advanced.

MR. FONG: Under our current TOU at this particular point there isn't much differentiation between the on-peak period and the off-peak period for residential. So that is the one thing that we would have to revisit to be able to have an incentive for customers.

PRESIDING MEMBER PFANNENSTIEL: But what I guess I am trying to get at, your plan for as you roll out these advanced meters, are you really going to use them for really trying to achieve some price response from customers? And if so, how do you go about doing that? Isn't it going to require both a good rate and good information to the customer?

MR. FONG: I think that is absolutely a true statement. Our first plan is to have the peak time rebate to get the demand response. The second you are raising is, should we have offerings that are more pure, closer to dynamic rates. Like a CPP rate for residential customers. And that is something we would have to visit at this point.

PRESIDING MEMBER PFANNENSTIEL: Yes.

MR. FONG: There is no disagreement from

me that that's something that we should offer.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Chong, you have a question.

CPUC COMMISSIONER CHONG: Yes. I guess I would like to emphasize the point that the Chairwoman is making. Which is, there is nothing that stops you once you have your smart meter in, from voluntarily offering a more aggressive rate to the residential customers to take advantage of the smart meter. And I think that is the point she makes and that I would like to pile on to.

I think if you are going to do customer education, take that money and let's really do customer education. Let's take that year to really teach the customer about dynamic pricing and the benefit it could bring them.

I just feel like we are doing a lot of baby steps when on a voluntary basis we could go further once that meter is in. So I would hope that the utilities that are here will take that to heart and really think, on a voluntary basis, what they might do once those meters start rolling in, in a more aggressive way.

And I would like to add my final thought, which is, how important the customer education component is going to be. I hope you have your most clever marketing folks on that. Because I think it will be fun, actually, and I think the customers are going to love it.

MR. FONG: Yes. I think it is not only the communication content, it is choosing the right communication channel that directs it and targets the customer. This is where it is new for the utility at this point, looking at the customer from that viewpoint.

PRESIDING MEMBER PFANNENSTIEL: Yes, it's amazing. The utilities have been around for how long and they are just now starting to think about price signals to customers. But I do think it is incredibly important. And I think it is not going to be a single channel, it is not going to be a single effort. It is going to be something that if the utilities are really trying to get the demand response out of these expensive meters that you are putting in and these sophisticated rates you have to work with the customers for some period of time. So thank you, Commissioner Chong, for piling on to that one.

ASSOCIATE MEMBER ROSENFELD: And I would like to pile on to the majority. That is your big opportunity to make friends with your customers.

This is a question I should know. When you say peak time rebate does that include time of use as well as the hot afternoons?

MR. FONG: Clarify the question. Is your question --

ASSOCIATE MEMBER ROSENFELD: When Andy defined critical peak pricing, for example, he wrote, TOU/critical peak pricing, which meant time of use, inextricably on hot summer afternoons, and critical peak pricing. I don't know how that translates in your mind to this compromise, the transient, the PTR.

MR. FONG: First thing. Usually the critical peak price is layered on top of the TOU rate.

ASSOCIATE MEMBER ROSENFELD: Good okay. I just wanted to make sure that I understood that.

MR. FONG: That's how you would have it.

ASSOCIATE MEMBER ROSENFELD: Good.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Ed. David.

DR. HUNGERFORD: All right. I am going to move to PG&E and Andrew Bell.

MR. BELL: I will try to keep this to

ten minutes. And I will preface my remarks by saying that obviously I haven't seen yet, we haven't seen yet the proposed decision that Mr. Campbell summarized a few minutes ago. Obviously these slides were prepared somewhat in advance of that and they reflect PG&E's position articulated in comments and at workshops preceding the issuance of the proposed decision. We will over the next several weeks need to review the proposed decision. There will be a comment period I'm sure in either 20 or 30 days.

I really just have four substantive slides. There are hard copies outside in the entrance area. If we can go ahead and move to the third slide.

This overview has been covered earlier today by Dr. Barkovich and also by Russ just a few minutes ago so I don't need to go into a great deal of detail. But we have been offering time of use in pricing at PG&E for nearly 30 years. The time of use rates, including on-peak demand charges and energy rates, have been mandatory for our largest customers since the late 1970s and we have had optional time of use rates since the mid-1980s.

We have had CPP rates as a new rate option for our largest customers for approximately the last five years. We do have in the larger size category, nearly 10 percent of our total sales already are to customers who made the choice to go onto critical peak pricing on a voluntary basis.

We also have an equivalent or perhaps more in terms of total sales that are not participating in critical peak pricing but are participating in interruptible curtailable tariffs or in the demand bidding program or in day-ahead capacity programs.

I haven't got this down to the last decimal point but I would say it is somewhere in the range of 25 to 30 percent of our large customer load is already participating in dynamic programs above and beyond TOU of one shape or another. With that intro I'll go to the next slide.

This slide I labeled prospects and opportunities. If you read the slide you will see that it is a, let's be careful about our expectations, slide.

In the far right, and you will be able

to see it on the hard copy, perhaps others around the room have seen this before. I saw it for the first time just a couple of months ago. It is a version of the Energy Commission's red state/blue state slide that ran in The Economist last fall showing what a great job California has done over the last 30 years in terms of overall energy efficiency. We are now on a per capita basis, across the whole state, at about 6,000 kilowatt hours per year per person, including all uses. The national average is closer to 10,000 and in some states the numbers are as high as 15,000.

I think that reflects the concerted effort over three decades of this Commission, of the Public Utilities Commission, of all three utilities. I also think that the state made a big decision nearly 20 years ago to institute revenue decoupling that got us all on board on doing that.

I have had the opportunity in a couple of different national conferences since I first saw this to try and sell revenue decoupling again nationwide. I think the states like Texas and the states in the Southeast could do a great deal in approaching us if they could do revenue decoupling and get on board too.

The point of including the slide in this context, however, is that you can only save each kilowatt once. You can do kilowatt hours through energy efficiency, you can do kilowatt hours through load shifting. You can do kilowatt hours through demand response. We don't want to rest on our laurels but we have achieved a great deal already and we have gotten a lot of the low-hanging fruit, if you will.

And if we continue to push energy efficiency, which may be a better fit for, for example I was just thinking, a McDonald's or a gas station, which may be in a better position to make permanent energy-efficiency investments and reduce load every day or do permanent load shifting, but maybe not in quite such a good situation to respond to dynamic prices that vary every day.

There are many different ways to skin a cat. There are many different ways to save a kilowatt. We are down this low. The next layer of kilowatts does get increasingly hard to get.

And I also point out on this slide that in the large customer market in particular, it has been well served by dynamic pricing programs for a number of years. We have got a lot of people participating in a lot of different ways, not just through the newer type of dynamic pricing.

If we can go to the next slide, customer perspectives. We do think we have opportunities for better commitment or better communication with customers as the new meters are installed. And we do think there are some signs of growing customer interest as they learn more about the new rate options.

We just got the critical peak pricing program, we call it Smart Rate for small customers. It is a streamlined program that is designed for the residential and small commercial market. We just got that off the ground within the last month.

The first rounds of mailings have gone out in the Bakersfield area. We are encouraging residential customers to open the envelope and pay attention to it by promising customers that they will get a $25 gift card if they sign up and another $25 gift card if they stay on for most of the first summer so that they can try out the program.

CPUC COMMISSIONER CHONG: A gift card to what?

MR. BELL: It's a basic gift card. You know, it's an ATM-equivalent card.

You know, you get so much mail in your envelope -- rather in your box every month. It's awfully easy to ignore stuff. It's a way of getting people to open and pay attention.

And it's working. Out of the first, I believe, slightly less than 3,000 residential customers who were mailed packages we got 300 calls. That's a ten percent response rate. Which if you know much about direct marketing, is an awfully good first round response rate. And I know over half, it may be two-thirds of those have actually enrolled in the rate. I don't have hard numbers. That was the first mailing, there are more mailings going out. But the results from this first round are promising.

ASSOCIATE MEMBER ROSENFELD: I guess I wasn't listening very carefully. This is very impressive so you woke me up.

MR. BELL: This is the residential critical peak pricing rate. Which is only available, obviously, after the smart meters, after the AMI meters are installed.

ASSOCIATE MEMBER ROSENFELD: Sure.

MR. BELL: This is the first summer it's been available. The first tranche of meters has been installed in the Bakersfield area so that's where we are marketing it.

ASSOCIATE MEMBER ROSENFELD: My question is, since it is entirely voluntary there is no AB 1X problem?

MR. BELL: There is no -- The Commission found -- The Public Utilities Commission found that there is no AB 1X problem because it is a voluntary rate. It is an overlay on top of our existing --

ASSOCIATE MEMBER ROSENFELD: It's entirely voluntary. You may have to bribe them but it is entirely voluntary. (Laughter)

MR. BELL: Correct.

PRESIDING MEMBER PFANNENSTIEL: It is not bribery, they are stimulating the local economy. (Laughter)

PRESIDING MEMBER PFANNENSTIEL: When you are saying, overlay. What do you mean, overlay?

MR. BELL: The customer is billed for their usual use at their usual tariff, whether it is the E-1 rate or whether it is the time of use rate. And then there is a surcharge that applies to their usage during critical peak price periods and there are credits that apply, discounts that apply to their usage outside of the critical peak pricing periods. At the end of the day you get these extra charges and credits that are applied to the bill.

PRESIDING MEMBER PFANNENSTIEL: So it's a pretty complicated and not very clean pricing, right? It is not one that a customer can look at and say, if I turn on my television set at this time it will cost me this, if I turn it on later it will cost me that. Because you still have to do it on top of your inverted rate.

MR. BELL: It is going on top of the -- we are balancing an awful lot of competing objectives here.

PRESIDING MEMBER PFANNENSTIEL: I don't understand why you still have tier rates if you don't need to have them.

MR. BELL: I have only got ten minutes here. I can go into slightly more of an explanation or perhaps we can follow up on that in comments. But this is something that we explored in the statewide pricing pilot and worked out.

The short answer, the short answer is

that if you rearrange all of the silverware on the table, so to speak, if you get rid of the tiered rates at the same time you introduce the critical peak prices, you are going to bring people on to the rate who are benefitting as a result of the change in rate structure, irrespective of what they can do in response to the critical peak pricing rate. And you are going to be making it hard for some people to join because of the --

ASSOCIATE MEMBER ROSENFELD: They don't want to give up the subsidy.

MR. BELL: Correct.

PRESIDING MEMBER PFANNENSTIEL: Yes, I understand that. But I am looking at ways to move them off of the subsidy onto a rate design that, in fact, has the advantage of having price signals that they really understand and can respond to. As well as having some cost justification for these price signals. In other words, higher costs when it is higher prices.

MR. BELL: I understand the concern that you have there. I will say that the higher price that applies during the CPP period for residential customers, it is a two to seven p.m. price signal. It is a 60 cent a kilowatt hour price signal. Now that is on top of a Tier 1 rate of ten cents or a Tier 3 rate of 20 cents or a Tier 5 rate of 30 cents. So it does vary. They do need to know what tier they are in.

PRESIDING MEMBER PFANNENSTIEL: Right.

MR. BELL: But it is a price signal that swamps. The 60 cent price is a price that swamps whatever tier level they are at.

PRESIDING MEMBER PFANNENSTIEL: I understand.

MR. BELL: I think that they will get the message that they will now -- they will also be getting messaging that reports when the high prices are in effect. I think that what we should do is go into a little bit more detail because this is a decision that was considered carefully in workshops and in the design of the statewide pricing pilot over a period of several years before the rate was rolled out.

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. BELL: I did want to respond to one of the questions that President Pfannenstiel has raised with a couple of the panelists about the question of mandatory versus default. And I will just convey one of our concerns.

A default assignment to us, we are concerned that it has an awful lot of the look and feel of a mandatory rate. If a customer's rate plan is changed without an affirmative decision to do it then it is sort of, if it walks like a duck, if it quacks like a duck.

It may feel more like -- when you're talking about a mass market and hundreds and thousands of customers it may feel more like a forced choice than an affirmative choice. Especially because I've heard a couple of comments up here about this being an opportunity that we should look forward to, to communicating with customers to learn how they can benefit from the new rates.

My concern there is that any revenue-neutral rate design is going to have as many losers as it is winners. You are going to have low-income people who have lost jobs who are home in hot areas who are needing to use air conditioning, or not even air conditioning but swamp coolers on hot afternoons and would be at a dis-benefit because they have a higher occupancy period during the peak period.

Even if they set the thermostat up to 85 degrees, if they are running flat-out on critical peak pricing days, when you go to more time-differentiated prices, yes, those are higher cost customers to serve, yes, in the long run they are people who should pay higher bills, but it is going to be difficult for those people to benefit from these kinds of rate choices.

And that is why we have tried to approach this carefully and why we prefer at the outset to do it on a voluntary basis. When it is not done, at the point where it wasn't done on a voluntary basis we have always taken the position that it should be done carefully and in small steps. Perhaps without putting the full capacity price into the peak price signal right away to soften the implementation, rather than doing it all at once.

PRESIDING MEMBER PFANNENSTIEL: I don't think you heard from me a problem on default versus voluntary. Because right now we have AB 1X. If AB 1X went away then you probably, I would probably be wanting to push more for default.

But right now, given the reality of where we are, it is a voluntary rate that you are going to be offering. And I do know that there will be winners and losers and as a voluntary rate then clearly the winners will stay on and the losers will go somewhere else. But over time you need to be moving to a more rational rate design.

And there will always be some subsidies in the system. I don't think anybody would argue against there being some subsidies. But I think right now the subsidies are unconscionable and we are looking for ways to move to a rate design that gives us the demand response that we are looking for in a more equitable way.

MR. BELL: I just want to say that the default mandatory question extends beyond residential. Remember that AB 1X only applies to residential rates. When I think about the gas station, when I think about a small chain store I think about the default mandatory, voluntary choice there too. And again I come back to that concern about perception.

PRESIDING MEMBER PFANNENSTIEL: So you are not planning to offer default rates to commercial customers. Default CPP rates to commercial customers.

MR. BELL: We need to look. Our position in comments and in workshops at the CPUC has been that we think these choices should be voluntary. I understand from the summary of the proposed decision that the proposed decision that has just been mailed says that it should be default. We need to look at what the reasoning there is and determine whether --

PRESIDING MEMBER PFANNENSTIEL: I was just looking at some of the numbers that we had earlier and about 80 percent of your commercial customers are on non-time-bearing rates. That's not industrial, just the commercial class. So it seems that you really haven't been pushing for time-bearing rates in the commercial class.

MR. BELL: It may be 20 percent by the number of customers. I think it is more line 35 percent. I don't have Bob's slides in front of me but I think it's more like 35 percent by sales. I think we have had an aggressive TOU program for a number of years and I think that we have had good participation in it on a voluntary basis.

Beyond time of use we also get to critical peak pricing. If we have customers who are not on time of use prices now and we look at doing time of use pricing and critical peak pricing at the same time. That's a couple of steps all at once that I have a bit of concern about.

And I also think it is important to understand that dynamic prices fundamentally are volatile prices. I have seen Dr. Faruqui's slide a number of times. It has that nice curve and it shows customers willing to accept risk benefitting from lower real-time prices.

And my concern when I see that slide is that that's a slide that shows us that in an average year perhaps a customer in real-time pricing might save five percent. But that might result from two years out of three them saving ten percent but having their bill go up by 25 percent in the year that they are not expecting it.

That is the kind of volatility that a customer is accepting when they go onto a real-time pricing rate. And I want customers to understand that risk. And I fear when I see slides like the one that Dr. Faruqui put up that those bury the risk that we are asking customers to take when they go onto a dynamic price.

If we can go to the last slide and then I'll stop. We know that the MRTU should be starting up this fall. We are going to be able to look at the first year or so of MRTU prices before we need to decide how appropriate they will be to get into real-time pricing tariffs.

An issue that we have touched on a little bit in the last hour or so has been whether real-time prices, the day-ahead real-time prices will really reflect capacity prices or not. If they don't reflect capacity prices that's the kind of thing you are capturing administratively in a critical peak pricing rate.

The one large-scale, time of use pricing program, or rather the real time pricing program in the US that I am aware of, the Georgia Power program I know has always had an administratively determined loss of load probability-based capacity price adder that gets built into it. So that's just one of these issues that one needs to look at. A real-time price may be partly based in the market and may also still partly be relying on administrative signals.

We don't know yet whether a real-time pricing tariff will be more appropriate as a one-part form or a two-part form. I do know that the Georgia Power tariff is a two-part tariff. I also confirmed just two weeks ago with people at

Georgia Power that their two-part tariff, which relies on customer baselines, most of the customer baselines have not been updated for 15 years.

I don't know how that works in Georgia. I do know that our customer baselines would have changed dramatically in 15 years in terms of how customers have changed and just who the largest customers were. I found that quite surprising.

One additional comment I wanted to make on the San Diego critical peak pricing program. Because I gather that I need to look at that in more detail when I evaluate our comments on the proposed decision.

But all of the critical peak pricing programs in California so far, and that is confirmed for me that that's still the case with the new San Diego program, rely on day-ahead notification to customers. You wait until the afternoon before rather than the morning-before. You wait until the afternoon before because that is when you have the best picture of what load conditions are going to be the next day.

However, it is long after the day-ahead market has already closed. So if you have an afternoon before, rather than a morning-before market, you are not going to have critical peak prices that have the opportunity to influence the day-ahead market prices. That's a tradeoff.

I think the customers will tell you that they would prefer to know when the system's conditions really warrant it. They would rather not get false alarms. But the market closes before it can be done.

That's the end of my comments.

PRESIDING MEMBER PFANNENSTIEL: Andrew.

CPUC ADVISOR CAMPBELL: Some comments on that last bit about how CPP works from a time line standpoint with the ISO market. I have had some conversations with ISO staff about this.

The way I discussed with the ISO that it would work is that PG&E, for example, could when submitting the schedule for the day-ahead indicate that if the price reaches, say, $200 per megawatt hour or some sort of price, that we need 25 less megawatts of power during this hour. And then the ISO, the market clears.

And then if the market clears below that price then PG&E would know not to call the critical peak pricing, a critical peak pricing event. And if the market clears at that price or above then PG&E could call that critical peak event. And so actually having the trigger for the critical peak event being after the ISO market is actually probably a preferred arrangement if you want to integrate that rate with the market.

And these some preliminary conversations I have had. There's not necessarily a conflict there.

MR. BELL: That is very useful to hear and I am glad this is a transcribed event. Because what I will do is I will take this snippet out, back to our electric procurement people and share it with them and find out how that works.

DR. HUNGERFORD: All right. I would like to shift gears just a little here and go to the publicly-owned utilities.

ASSOCIATE MEMBER ROSENFELD: David, closer to the mic, again.

DR. HUNGERFORD: I would like to shift gears and move on to the publicly-owned utilities. I think SMUD has a presentation so we will go with that first and then give a couple of the utility representatives an opportunity to make a statement.

MR. LANDON: Good afternoon, my name is

Rob Landon. SMUD has been following the filings, the IOU filings very closely. We have also been engaged in some customer outreach and research. I would say we are not at the, we are not at the point of the IOUs in terms of pilot testing our rates or market testing but we have had several discussions in the last quarter of '07, presentations to our board. So I will focus on some of those rate concepts today.

The next slide shows SMUD is, as many of the utilities in California -- I don't have anybody to advance to the next slide.

PRESIDING MEMBER PFANNENSTIEL: David, you are going to have to move the slide.

DR. HUNGERFORD: I am.

MR. LANDON: Focusing on the critical hours. About 40 of SMUD'S hours comprise about 400 megawatts of our peak. Most of those peak hours occur in July and August. And the next slide points out that the SMUD Board recently changed their rate policy. These are found in what they call SDs or strategic directives. And SD-2 is our rate directive.

Adding a few elements reflecting the cost of energy when it is used. That is, the district rates will be designed to balance and achieve the following goals. And so reflecting the cost of energy when it is used. Reducing use on peak. And offering flexibility and options for a few of the areas that they added.

And the next slide summarizes our basic TOU offerings. We have, we have had for some time about 31 percent of our system load, customers of 300 kilowatts and above on TOU rates.

In our rate concepts -- I guess I can just discuss those in general -- we look at options such as a TOU with demand charges, critical peak pricing, which is kind of our basic TOU with a critical peak price on call days, and real-time pricing. We actually did have a real-time pricing rate in place a few years back but we had no customers interested in taking that rate.

Our entire commercial class on TOU, it would comprise about another 19 percent of our system load. So over 50 percent then would be on TOU.

There is an AMI RFP currently out on the streets. We expect that to be awarded the last quarter of '08. So TOU rates, in our mind, are tied to the hip to the AMI roll-out schedule.

And the last slide. Our full AMI deployment would be in the '09 to 2012 time frame. So at that point we would have or we would offer all customer classes TOU rates.

The residential class we currently have on tier pricing, much the same as the IOUs, only a three tier arrangement. Many of you are familiar with that, I'm sure.

We have considered a hybrid rate in a tier and a TOU overlay combination. And I can talk about that in a minute. It may be a transitional concept that many of our residential customers thought was a good idea. We are asking essentially for demand reduction or time of use pricing when the district really needs the demand response.

And then critical peak pricing is another option that we would be offering to the residential customers.

And the next slide illustrates some of the rate designs. Which graphically the tier pricing is what we currently have in place. The TOU overlay is essentially for the summer months when we really need, you know, the load relief, as I mentioned.

From a customer education outreach standpoint. They already know what their bill looks like and their rate as they know it. Adding that TOU component, which we would consider a legitimate time of use rate in the summer months, would add the same -- it would essentially be an adder on a bill. The billing would be during those four summer month periods for that four to seven time period when our cost is the highest.

The next rate back over on the left, the lower left, illustrates the time of use pricing. It is, again, a three hour time period, four to seven, for all customer classes. That would be an option for any of the customer classes when AMI is available.

And then finally our critical peak pricing, which is based on a standard TOU. But it would be -- In the peak period we would offer the critical peak pricing. And we tested a couple of concepts with our customers. Whether we have a higher critical peak price, let's say in the 60 cent range, for fewer calls. Let's say we have a two hour duration in the call. So we call that, let's say, ten days of the summer, the ten most critical days, at a higher price. Versus maybe more calls, say 20 calls for -- Let's see. I guess it was two hour blocks again. So that would comprise our 40 hours.

They seemed to prefer -- The business customers anyway. The next slide discusses the customer feedback that we got. First of all the customers really understood that SMUD's cost of supplying energy is higher in the summer, especially in very hot weather.

Customers understood that they would pay higher rates over fewer summer months and lower rates over more winter months. Most of the customers like a narrow, three hour, super-peak period.

And on the commercial feedback we got customers who find it difficult to shift load or have a flat load factor prefer a demand charge rate.

Customers want a minimum of 24 hour notice for a CPP call. And they prefer fewer CPP hours with higher prices, which was the point that I was alluding to earlier. Versus more hours with lower prices.

And the residential customer feedback. Customers with flexible lifestyles said that they will shift activities off-peak. Again, the residential energy savings from time of use shown on their bill. They like to have that savings available to them over maybe a current rate or a standard rate.

They really like the idea of having choices. So rather than having, you know, one or two sizes fit all they like the idea of time of use options. That's a little bit of the customer feedback.

I might mention that SMUD has a process that has been called a compact with the customer. It's pretty well documented on our website. It's the idea that we are looking to our customers for help with demand reduction, energy efficiency and environmental issues so those choices or options will be developed for them to consider when the AMI meter is rolled out.

That's about all I have right now.

PRESIDING MEMBER PFANNENSTIEL: Great. Questions.

ASSOCIATE MEMBER ROSENFELD: Yes, I have just a factual question. I am not a SMUD customer. What do you do about tiers? Tiers keep coming up.

MR. LANDON: Currently our residential metered customers, we do have time of use rates in place or options for customers that select time of use. And your question, Commissioner Rosenfeld, what do we do about the tiers?

ASSOCIATE MEMBER ROSENFELD: Do you offer, on your regular rates for that time piece.

MR. LANDON: Yes, yes. For some time we have been offering tiered rates for residential customers.

ASSOCIATE MEMBER ROSENFELD: When you offer the time of use is that on top of the tiers?

MR. LANDON: No.

ASSOCIATE MEMBER ROSENFELD: No. It's a clean slate.

MR. LANDON: Yes, yes. We have offered time of use rates for many years to our residential customers. Occasionally somebody will call in talking about their bill and they have a load perhaps that is flexible or they are going to shift and so we'll suggest a time of use rate. And we do rate comparisons for customers that ask for those.

ASSOCIATE MEMBER ROSENFELD: Thanks.

ADVISOR TUTT: To follow up on that just

a little bit. The tiered TOU overlay then was just a concept, it is not an actual rate that is out there with customers?

MR. LANDON: We are not currently offering that to customers. We are discussing that with our Board as a part of the option that will be offered to customers once AMI rolls out. It is a hybrid rate so to some extent we have had discussions with our staff about the energy efficiency signals, the price signals that tiered rates offer customers.

And to transition away from those kinds of rates may, to a pure time of use rate, may confuse customers about the value of energy efficiency. So developing this concept we think is -- and it is an alternate to critical peak pricing perhaps. You get sort of the best of both worlds.

SRP, I know they must have been looking at our Board presentations because they recently came out with a very similar rate proposal, which was accepted by their Board. They are currently offering that rate.

ADVISOR TUTT: I think they have a hidden camera in your board room actually.

MR. LANDON: They very well may, that could be true.

ADVISOR TUTT: The last slide that you have in your presentation talked about TOU rates being offered as AMIs deployed.

MR. LANDON: Yes.

ADVISOR TUTT: But I guess I understand from your answer there that it's not necessarily just TOU rates. There's a variety of rate options that you might be looking at as AMIs deploy.

MR. LANDON: That's correct. That should probably say TOU rate options.

ADVISOR TUTT: Including potential CPP rates.

MR. LANDON: That's correct.

ADVISOR TUTT: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Okay, thank you. I notice we have three speakers left on the panel and we are running out of time so I think we will ask them to -- But I guess no more presentations?

MR. CHEN: No.

PRESIDING MEMBER PFANNENSTIEL: We'll just hear and ask questions. Go ahead.

MR. CHEN: In LA we have had a rate

restriction for the last 15 years. It is good or bad? So far I think -- We have about 35 percent total load is on TOU rate and we have interruptible rate. We also have a cogen rate currently implemented.

And we are putting in an AMI system that can in the future be very flexible. Any kind of rate we can go in and adopt with that new system. We are targeting on the large commercial customers and the medium customers and also the high users on the residential customers.

This week we are going to the City Council for a rate restructure. We are going to propose the residential rate be a tiered rate and also we are going to mandatory TOU for large users, for the residential users. The top five percent will be mandatory TOU. And also we are going to move our TOU requirements from 100 kW currently to 30 kW.

So that will probably cover our total 50 to 55 percent total load on TOU rate. And with our system, the AMI system, we can do a lot of flexible rates. Like a CPP rate in the future if we needed to.

Also we are looking for, like Ed

mentioned, the targeted solution for different segments. Like the billboards. If they don't need it in the critical time then we can remotely turn it off. On some freeways there's a lot of those billboards in LA.

And also cogen. We like to have the cogen generators fired up on those critical times. So we try to, you know, do more catered rates so that hopefully that will get us, you know, somewhere close to what we want. The five percent critical load shift for us. That's the summary.

And I like SMUD managing their tier rate on top of the TOU. We're probably going to look into that in the future. It is pretty easy to implement as long as you have a TOU meter. I think that's all you need. It's not that much more. Thank you.

PRESIDING MEMBER PFANNENSTIEL: George, you are rolling out AMI to residential customers now, are you not?

MR. CHEN: The top five percent. About 65, yes. Fifty-five southern customers we are thinking of putting them on two-way communication residential meters. Hopefully coming with the mandatory TOU we want to give them some control.

They can do some, you know, shifting. That gives them some choice there.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Others?

ADVISOR TUTT: But most of your residential customers will not be on the full AMI we discussed in a previous workshop. They'll be on -- I think the term is actually it's an interval meter but more like a TOU meter.

MR. CHEN: The IF meter, you can read it remotely, on the street curb or drive-by. No, they are not TOU.

ADVISOR TUTT: They are not TOU.

MR. CHEN: Right.

ADVISOR TUTT: So you won't be rolling out TOU rates to those customers or CPP rates to those customers. You won't have the meters for them, for most of your residential customers.

MR. CHEN: If it is required. If it is really, you know, the price goes up out of whack, you know, later on. Then we can put a network out to read those meters continuously so we can have interval data and we can do the TOU from that.

The meter we deploy is pretty flexible. You know, it's one way but it keeps on sending the signal out. And if it needs to be we can put a network to just collect it in one radius, you know, miles. Then we can pick up those readings and we can do the TOU.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Go ahead.

MR. BADGETT: Good afternoon. My name is Steve Badgett, again, and I will be trying to wear two hats today if the Commission is okay. One, representing the Southern California Public Power Authority, I'll refer to them as SCPPA. As you know or may not know, it is an organization that represents 11 cities, publicly-owned utilities in Southern California and one irrigation district, the Imperial Irrigation District.

Collectively we serve 25 percent of the load in California. Seven million residents in that service territory. However, Los Angeles Department of Water and Power, my colleague who just presented, is a big part of that. So I want to talk about the balance of those utilities and the irrigation district. They range from about 20,000 customers to 110,000, 115,000 customers and their load ranges from 35 megawatts to 650, 700 megawatts.

All the SCPPA utilities and participants are involved in some way, form or fashion into trying to promote demand response. We like to consider those approaches as tools in our toolbox. Energy efficiency is a big one but also TOU rates, tiered rates. Our approaches to smart grid and AMI technologies are certainly a part of those tools.

We are Southern California service territory. Our load is air conditioning peak load and it is a very challenging load. We try to mitigate customers who are experiencing, like you can in Sacramento, 110 degree days, 85/90 percent humidity. You can have bells going off and red lights flashing. But as expressed by the PG&E representative, a lot of these people have to make that decision and regardless of price they are going to turn on that air conditioner. So we are trying to look at energy-efficiency as well as a tool to help us mitigate those challenges that our customers have.

Now I want to put on the Riverside hat just for a minute. We are 105,000 customers, 610 megawatt peak. In May of this year our peak for

May was larger than our all-time high of 2004 or before. So we are seeing a great growth in Riverside as you see in California. And how do we, how do we try to provide a demand response program to that climate challenge that we have regarding use of electricity.

Riverside is not the 80/20 rule but our top 200 customers represent about 80 percent of our revenues and that is about 65 percent of our demand. So we do have programs in place that look at those particular customers. We actually have a customer service representative dedicated to those customers. We have both Internet and email and certainly phone call and personal. We know who we want to call when we want to talk to them about those type of programs that we have with them to reduce demand. They are a challenge.

Those 200 customers, the largest one is the University of California in Riverside. They particularly, unless it is an emergency, want more than a 12 hour notice to start pulling back on some of the programs they have, which is agriculturally based. A lot of professors in there with their programs and they only want to see a cutback when there's an emergency. And a lot of our manufacturing and other customers as well.

The challenges with our smaller customers. We've got a lot of small retail, the hamburger joints, the haircut salons, those type of things. It's a challenge for them to cut back. Dimming lights in a retail establishment, since it's an air of emergency, not necessarily an air of trying to reduce energy. So we look at ways to help them.

One of the things we're working where we are shifting a fundamental approach. Riverside does offer a 50 percent rebate, up to $25,000, on a photovoltaic array if you want to put it on your residential home. More if you want to put it on your businesses. Those attract people that can afford it.

The people we are trying to work toward are the ones who can't afford their energy and a lot of times can't make those decisions to turn off their air conditioner. So we are focusing on trying to take what we can put into a photovoltaic rebate we can weatherize 10 to 15 homes. Our housing stock is pre-1975, 50 percent of our housing stock. Which is a replica of what

California is.

If we can get weatherization programs in there we are going to see some truly energy efficiency -- somewhat demand response but definitely total energy consumption reductions. Both in the winter, which is not a huge load for us, but for the gas industry, the gas utility, it does represent some of their challenges as well.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Steve.

MR. BADGETT: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Last but not least, Mr. Pretto.

MR. PRETTO: Thank you. I am here on behalf of NCPA and Santa Clara. I think from an NCPA perspective, as we approach critical peak pricing and demand response activities we are also vitally interested in those.

But as utilities go we are a diverse group of utilities. We range from Santa Clara, whose average load is about 400 megawatts. And we are in the Bay Area along with Palo Alto and Alameda and the Port of Oakland and BART.

We don't have any air conditioning to speak of so our needs on demand response can be terribly different from some of our colleagues in the San Joaquin Valley and Sacramento Valley, Redding, Lodi, Roseville. They have just a different air conditioning component as we all know.

Also Truckee/Donner is a member of NCPA. Truckee/Donner's load profile is fundamentally different from any of us.

So as we approach policy in this area we would like to have, be able to have in a sense a diversity amongst our members recognized so that as we look at programs that we can look at the ones that will be most effective for us.

So for example -- The other point I would make is that the load profiles of the utilities being dramatically different, the system load factors are dramatically different. Santa Clara's system load factor is 75 percent. For us to cause load to shift from the on-peak to the off-peak is not an easy proposition.

In fact, as we approach energy efficiency and CO2 reduction we'd prefer to focus on energy efficiency. It's energy efficiency that will -- lighting. We have programs where we will go into an industrial plant. We will review industrial processes to see where you can save energy. The other places that we think would be very effective are building efficiency standards, appliance efficiency standards.

Those are the kinds of things that would save energy and indirectly, even though we wouldn't be doing them directly but those would help a Santa Clara and an Alameda and a Palo Alto. If you get out into the San Joaquin Valley where you have demand response being much more important, that's where pricing programs can make a difference but also efficient energy air conditioners could also make a big difference. And so we would ask that we also look at those.

In terms of peak demand response. We do have some peak demand response programs. We have one interruptible contract where we can get eight megawatts of interruptibility and we can do it up to, I believe it is something like 30 times a year for economic reasons or any other reasons. But the benefit of doing that is embedded in the contract price. It is not a particular payment for reducing load directly.

In emergencies. And we evolved this in the energy crisis back in 2000. We can call on 15 to 20 megawatts of peak demand reduction on a -- I would call it an emergency basis, say like a Stage 3 emergency. And we do it voluntarily. We're small and we are able to work closely with our large customers so we have done that.

The other thing that I think is important and hopefully can get recognized in terms of tailored response to various pricing issues is in your capacity profile and demand profile. I think that is very important.

Santa Clara, for example, is very long on capacity. We have enough capacity to meet our load for the foreseeable future. What we will need as we go forward is energy so we are looking to figure out how to acquire energy. And because we have a significant hydro component, roughly half of our energy is provided from large hydro. No, it's 20 percent, I'm sorry. Trying to get the numbers right. Twenty-five percent or so is from large hydro, whose flow is focused in the spring and summer.

So interestingly enough, when we look out for our future energy needs our energy needs are, interestingly enough, in the winter. And so in terms of how we price power to our customers compared to what are, is called our marginal needs, are, it creates some tailoring issues that may be unique to us. In a sense we would like to have our uniqueness recognized so we would have the flexibility to deal with it on the most cost-effective manner that works for us.

And I think that same thing could be said of the other NCPA members who have their own unique load profiles and resource profiles going forward. I think that's kind of the viewpoint I would like to express on behalf of NCPA.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mike. What are your basic residential rates? What form do they take?

MR. PRETTO: Our basic residential rates. We have a first 300 kilowatt hours for residential and an over 300 kilowatt hour block. But there is also a time of use option that goes with those. The other thing I would point out in terms of our sales profile, 85 percent of our profiles are large commercial/industrial and about 8 or 9 percent of our sales are residential.

PRESIDING MEMBER PFANNENSTIEL: And the meters that you have on your residential, they're basic. Since you have a small residential base you are not moving to advanced meters?

MR. PRETTO: Actually we are in the process of installing meters. I believe it's several thousand. In this budget year there's meters being installed as we speak.

PRESIDING MEMBER PFANNENSTIEL: And then your commercial customers. Are they on time-varying rates of some sort?

MR. PRETTO: We have a basic commercial rate, which has a time of use option that we installed last year. Actually it was in response to the Energy Policy Act of 2005. There were some requirements. And so we did implement time of use rates for residential and commercial and large industrial customers.

PRESIDING MEMBER PFANNENSTIEL: And are they all optional? Any default or mandatory?

MR. PRETTO: They are all optional, yes.

PRESIDING MEMBER PFANNENSTIEL: No.

MR. PRETTO: They are optional.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Any other questions of this panel? Andy, yes.

CPUC ADVISOR CAMPBELL: A question about how is Santa Clara interconnected with the other members of NCPA and the rest of the world. I know there are opportunities even with a relatively flat load. If Santa Clara members, some of your customers can reduce their load to be able to capture some value or sell some energy to the other --

MR. PRETTO: We are -- Obviously we are interconnected with the California ISO. We also have our own power trading operation. So to the extent that we have power available or need power we can and do trade in the wholesale markets.

As for other members of NCPA, most of the other members, except Redding, are part of what is called the NCPA pool. And their purchases are in fact pooled for planning and scheduling purposes and there is a process by which power can be transferred and traded amongst the members of the pool.

PRESIDING MEMBER PFANNENSTIEL: Tim.

ADVISOR TUTT: The question I had for the panel is related to the use of load management standards. The last time we used our load management standards authority back in the early '80s we, I guess, asked or required five utilities, including SMUD and LA, to develop marginal cost rates. There was a list of five or so potential concepts in the notice for this.

I don't know if you want to talk about it on the panel but I'd appreciate it in written comments if you would address what kind of load management standards we could employ in this area or whether we should or shouldn't. Should they be statewide. Should they reflect the differential circumstances of some of the POUs, et cetera. Is there anything you would like to say as part of the panel or would you like to talk about those in written comments?

PRESIDING MEMBER PFANNENSTIEL: It looks like written comments it will be. Thank you. Thank you all, I appreciate this panel. Very good information.

Our next panel is on customer perspectives. As they are being seated I am going to offer an apology that I have to leave shortly to go to a different meeting. I thought I was going to be here through this whole panel but we are running a bit later than I thought we would be. So accept my apologies and Commissioner Rosenfeld will continue to chair.

David, how would you like to organize

the presentations?

DR. HUNGERFORD: The customer panel, there's only one presentation. There's only one presentation from the customer panel. Although like in the utility panel we would like each of them to have an opportunity to comment.

So I think we should start with a round of introductions. We can start over on the Commissioners' right with Ms. Lee from DRA.

MS. LEE: Hi, I am Rebecca Lee at DRA. And DRA stands for the Division of Ratepayer Advocates at CPUC.

MR. ROBERTS: I am Bill Roberts, Economic Sciences Corporation. I am a consultant for Building Owners and Managers Association of California, BOMA. I represent them in rate cases and other regulatory affairs.

DR. BARKOVICH: Barbara Barkovich again for the California Large Energy Consumers Association.

MR. NAHIJIAN: I am Jeff Nahijian, I am with JBS Energy. I am here on behalf of TURN, The Utility Reform Network.

DR. HOUSE: I am Lon House. I am the energy advisor to ACWA, the Association of

California Water Agencies.

DR. HUNGERFORD: And the one who provided a brief presentation.

DR. HOUSE: Let's go on to the next slide. I'll run through this.

There is substantial potential within the water community for additional demand response. And I want to just go through them and talk about some of the problems we had.

All the water agencies that supply treated water in the state of California have some storage.

But that storage was added for water system operation and it has not been added for energy or on-peak demand electrical demand reduction.

And with existing storage there's limits to the amount of reduction that we can use from the existing storage.

And the current operation within the water community is very conservative. It was built by water engineers, it is operated by water engineers, and energy is sort of a secondary consideration.

On the next slide you will notice that

the water agencies do right now, and this is 2004 summer peak, reduce a substantial amount. Hundreds of megawatts of demand during the on-peak period. And this comes from two reasons. One is, we have a bimodal water demand, we have a morning peak and an evening peak. And it has to do with the use of storage. Next slide.

Additional storage can yield some fairly substantial results. And some of you have already seen this; this is the El Dorado Hills fresh water system. And what happened is we went in in 2003 and they were looking at adding, they needed to add some additional storage for load growth. And so we did an analysis on adding that about three years early.

And you can see the top one, the top slide is their demand on June 14, 2004. The bottom slide, and this additional storage was added in the fall of 2004. We tested it throughout the spring of 2004. And then you can see in June of 2005, you can see that in this case about two megawatts was dropped during the on-peak period.

The next slide is I have included in my handouts out there a report that was written, a publication, just to emphasize that the decision-making between public and private sectors is very different. The private sector and -- The rate design is traditionally and almost exclusively designed for the private sector.

But when it is translated over to the public sector the public sector has different decision-making criteria. They have different risk/reward behavior. They have different investment decisions. And this article that I won't go into has a discussion of all of those various things.

So in summary, there is probably between 500 and 1,000 megawatts of additional on-peak demand reductions that could be realized within the water community. Some with the existing storage, most of it with the addition of additional storage.

Additional storage will yield permanent on-peak demand reductions and additional demand response.

But the current and proposed rate design is neither consistent enough nor attractive enough to warrant water agency storage additions for energy use.

And the final point is the incentive and decision-making for public agencies is very different from private customers.

And the utilities' proposals thus far have been directed toward private customers. And you don't see a great deal of interest in the public sector in participating in traditional demand response programs as they are currently constructed. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Questions?

ASSOCIATE MEMBER ROSENFELD: Yes.

PRESIDING MEMBER PFANNENSTIEL: Art.

ASSOCIATE MEMBER ROSENFELD: Lon, I guess I am not quite clear as to what you would have changed in the way of rate structure so as to be able to, I guess, finance more storage.

DR. HOUSE: Well the issues, and let me preface this right. For the near term, in the next couple of years the water agencies really aren't going to be paying much attention to energy. We have much bigger problems. As you know the problems that we are having, facing supplying water to the state.

So what you will see in the next couple

years at least is an increased energy use on the water agency side. Because as we go from the lack of surface water into the drought situation that means we're doing conservation programs but we're replacing that with ground water that is being pumped. So you will see energy use go up within the water community.

The problem has been that these are very capital intensive projects, number one. And they are very, they have a very long life, 20 or 30 years. And so a lot of the things that you -- when a water agency makes a decision that they don't need to do for their water supply for energy savings, they need to be able to say yes, that we are going to be able to pay this off over a period of time.

And there have been so many changes in rate design and opportunities in the last probably decade that the water agencies are just saying, we have to wait until things calm down. Because it takes us a long, long time, five, ten years to pay for this new storage facility that may be $10 million. And we don't get any of the benefits, the tax benefits associated with the private side. We don't get accelerated depreciation, we don't get investment tax credits, we don't get any of that stuff.

And so we are going to just concentrate on our primary responsibility, which is water. And if some of this other stuff comes by, like the case with El Dorado, and we can accelerate a project that we were going to do and it makes sense, we will do it because we will have a payback in a very short period of time.

But to build one fresh you will need some substantial consistency, which is like five years or so consistency, in the rates that that decision is made under for the water agencies to attempt these large, capital-intensive projects.

ASSOCIATE MEMBER ROSENFELD: I should know this but I don't. Where do the water agencies buy most of their electricity? Is it from publicly-owned utilities, is it from PG&E?

DR. HOUSE: The water agencies buy most of their electricity from the investor-owned utilities. And that's because the publicly-owned utilities, most of them supply water as well as electricity. So you get -- SMUD is an exception. You get LA, you get Imperial, you get Modesto, you get Turlock. They were originally set up to supply water and electricity both.

And then you've got the state, the state and the federal projects that supply the transfer of the water down. But most, almost all the water agencies, as we define water agencies in the state, buy their electricity from the investor-owned utilities.

ASSOCIATE MEMBER ROSENFELD: So that means Rachelle Chong tells us how you get stability into this market. (Laughter) Okay.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Thank you, Lon.

DR. HUNGERFORD: Let's rotate back the other way and Mr. Nahijian.

MR. NAHIJIAN: Yes, thank you. I will make my -- In deference to Dr. Hungerford I will make my comments very short.

I guess in general -- And we'll probably repeat the comments we have been repeating for a number of years now. We are very skeptical about being able to use dynamic pricing to achieve demand response for the residential class.

We still are very strong proponents of inverted tier systems because we feel that they have provided the most cost-effective signals to customers to conserve energy. And we believe that energy efficiency is being at the top of the loading order, the most important thing.

We felt that in terms of getting demand response from the residential class, we think direct load control is clearly preferable and much more effective than pricing. Things like air conditioner cycling programs, some types of appliance load control programs. We feel that those have shown themselves to be cost-effective when priced correctly and to provide some very valuable demand response to the ISO as well as the utilities.

In terms of moving to dynamic prices for residential customers. We have to sort of start with some of our data in terms of knowing our customers. And one of the data points that we have done in terms of our analysis is trying to find out how much is supplied by or how much load is associated with the residential class.

And what we found is basically 50 percent of the residential customers in the state, in general, consume only 25 percent of the energy. So there's not that much there. Most of those customers don't get out of 130 percent of baseline.

Again, as also said today. Because of that fairly low per capita energy use, load shifting is very difficult for these folks. I also don't represent, should we say, a universally intelligent customer class. Which is why they need representation. (Laughter)

They are not, they are the least sophisticated and unable to deal with some of the pricing signals here. They don't have the resources to be able to be sophisticated in knowing when the prices are available or not.

In terms of small customers what we found is that some of the smaller customers actually have much better load patterns and could structurally benefit from some of the CPP rates that we have seen. However, the irony there is that they still don't have enough load shift to be able to pay for the advanced meter that is being foisted on them in terms of rates.

If the AMI proposals were more cost-effective on an operational basis that would be somewhat of a moot point because those operational savings could pay for the AMI for those small customers. But unfortunately, because they are not operationally cost-effective, or even close to it, they won't. So the small customers will not be able to save as much.

The large customers. The ones that burn unusually large amounts. You get into the fourth and fifth tier. Those customers don't have the same load patterns and they may be able to -- they would then get the incentives to shift load. But then you will also find that those customers also have a correlation of much higher incomes and that energy bills as a percentage of their overall income is much smaller. And so you are going to see these people just basically buying through interruptions. So you are not going to, again, get the peak demand or peak load response that you are sort of looking for.

In terms of going towards a real-time pricing for residential customers. That's a very, we think that's a very difficult thing. And again pointing to the non-sophistication of residential customers. There's some smart ones out there but it's a small, it's a very small percentage.

And one of the confusing things in terms of real-time pricing I can give you as an analogy, the current prices. The current gas prices change once a month on the beginning of the month to provide the current monthly gas price to every customer. To all the residential customers, everyone.

The residential customers don't know what that gas price is until they receive their bill at the end of the month. And because the gas price changes at a different interval as the billing cycle oftentimes you will see that there's a gas price associated with maybe the first seven or eight days and then the remaining days are associated with a different gas price. Then that gas price gets prorated over the number of therms.

And the customer gets the bill and he scratches his head and he says, well okay, I'll pay it, whatever. But they don't know what the bill is and they didn't have that to be able to react proactively to reducing their demand in that term. That's only for 12 price changes a year. If we get into real-time pricing where some proponents are talking about 8760 price changes per year we're getting to even more complications and even less ability to sort of change into that.

We believe, frankly, that one of the problems with this too is that with all the AMA and the dynamic pricing and all of this need to educate customers and get them proactively involved it is just going to be basically about 30 percent of people that just are not going to be able to do this. They are going to be low-income customers. They are going to be seniors on fixed income. They are not going to be computer savvy. They are not going to be able to understand what is going on and they are going to be basically skeptical and be victims of this. So that is one of our major concerns.

So in terms of our particular preference in terms of trying to get demand response from the residential class, we have a couple -- what our solutions are.

Our first solution is energy efficiency. Much tighter energy efficiency standards for air conditioning. You know, we are suffering greatly. We are out here at SEERs of 12 when we could easily go to 16 and we could save a third of our demand response there most cost-effectively.

The next one would be direct load control and some of the air conditioning load control programs that we have seen.

ASSOCIATE MEMBER ROSENFELD: Jeff, you

will be pleased --

MR. NAHIJIAN: We have looked and tried to study the latest trend in that sort of direct load control, which is smart thermostats. And we have seen studies that show, at least recently from some of the PG&E programs, that really essentially the smart thermostat does not provide the same demand response.

That those are probably in order of maybe a half, depending on the time, on the heat of the day in that particular zone that it's in. It really is substantially less demand response and the smart thermostat costs close to two, almost three times as much to both buy and install as an A/C cycler.

So that's pretty much what I had to say.

ASSOCIATE MEMBER ROSENFELD: One small comment. We, of course -- It's not the demand response part of the CEC or the PUC that has to do with air conditioning standards. I will say the good news is that the country has now been broken up into three climate zones. We will get better air conditioners. DOE has finally, under court injunction, called for beginning to start that process. I think we will to a SEER 16.

MR. NAHIJIAN: Good, good.

ASSOCIATE MEMBER ROSENFELD: I didn't understand. I welcome you to the panel in nine days when we discuss enabling technologies. And I think you will see demonstrations of PCTs which are under $100 retail. I think you should withhold your statement that their price is going through the roof.

I have a question for you, Jeff. You said something at the very beginning that I just wasn't paying attention to. Something about 50 percent of the residential customers only represent 25 percent of the load or something. What did you say?

MR. NAHIJIAN: We found in our analysis, in general, 50 percent of the residential customers burn 25 percent of the energy.

ASSOCIATE MEMBER ROSENFELD: Of the residential, of the class energy.

MR. NAHIJIAN: Of the system energy.

ASSOCIATE MEMBER ROSENFELD: I don't understand how to put those together. I have to know what 50 percent of residential customers --

MR. NAHIJIAN: Say, for instance, of all the system energy for say PG&E.

ASSOCIATE MEMBER ROSENFELD: Yes.

MR. NAHIJIAN: Fifty percent of the residential customers account for 25 percent of PG&E's energy load.

ASSOCIATE MEMBER ROSENFELD: That doesn't compute to me unless I know what fraction of the load is residential.

DR. BARKOVICH: It's about a third. A third to 40 percent. It depends on the utility.

MR. NAHIJIAN: Maybe 40, maybe more like --

DR. BARKOVICH: It depends on the utility.

MR. NAHIJIAN: Yes, depending on the -- Forty or forty-ish.

MR. GARWACKI: I guess what you probably mean is that 50 percent of the customers account for 25 percent of the class load, not the system.

MR. NAHIJIAN: I am not sure that -- I don't -- I think that -- Because the residential class uses 40 percent. And these people I'm talking about not getting out of baseline, out of 130 percent of baseline. I can re-look at those numbers but I think that's --

ASSOCIATE MEMBER ROSENFELD: I don't

understand. A, I don't understand what I am supposed to understand from this and I am not sure what you are selling from that number.

MR. NAHIJIAN: What I am saying is that a large number of customers, a large percentage --

ASSOCIATE MEMBER ROSENFELD: Andy is going to help you, I think.

MR. NAHIJIAN: No, I'll stand corrected. But, you know, let me get back in written comments and make sure -- let me make sure that I have that right. Even so, if we have 50 percent -- As Andrew is saying.

MR. BELL: I think that --

MR. NAHIJIAN: You're probably referring to the class load.

MR. BELL: I think that what --

ADVISOR TUTT: Please speak into a mic.

MR. BELL: I think that what Mr. Nahijian was trying to talk about was the low-end usage residential customers. And I think what he was saying was that the lowest 50 percent, the lower half of the residential users use 25 percent. Not of total system energy but of the residential class energy.

ASSOCIATE MEMBER ROSENFELD: Of the

class.

MR. NAHIJIAN: Okay.

MR. BELL: And within round numbers that sounds about right. We do have -- I think in a typical month 60 percent of our customers don't get out of Tier 1 or Tier 2. The ones who are up into Tier 3, Tier 4 and 5 do account for a much larger share of total usage.

ASSOCIATE MEMBER ROSENFELD: There was one other thing I just didn't understand. You made some point that a lot of customers can't respond to time of use pricing or to critical peak pricing. But at the same time you came on strong for air conditioning load control, which is forced response. That seems to be a little bit --

MR. NAHIJIAN: Actually I disagree that that's forced response. Most of the proponents or the people that have been against that sort of issue have said that that is taking away customer choice and we strongly believe you have customer choice. It's a voluntary program. You have a choice to be on the program or not. That is your customer choice. We don't feel it is forced. You went on the program voluntarily.

ASSOCIATE MEMBER ROSENFELD: So you

would argue that if you have critical peak pricing that that should also be voluntary.

MR. NAHIJIAN: I am not going to argue either one on that. Because I can only see, I can see problems with both ways.

ASSOCIATE MEMBER ROSENFELD: Thanks. Other questions for Nahijian? Thanks, Jeff. Dave.

DR. BARKOVICH: I guess nobody wants to go next so I'm it by default. I am not going to say a whole lot here because I know it has been a long day already. But I do have a few points I would like to make on behalf of the large process industry customers that I represent.

One of the things I always need to say is that the customers I represent account for a very significant fraction of all the interruptible load, i.e. reliability-based DR of PG&E and Edison. They are strong supporters of maintaining interruptible rate options and providing that kind of emergency response. It has an excellent track record of providing load reductions over almost 25 years now.

And I can honestly say that if those customers were transitioned to a price-based program I would be very surprised if you would maintain that amount of participation in terms of potential load drop. I can't say for sure because it hasn't happened. But they are committed to being available on an emergency basis because they think it's the right thing to do. And frankly they get a rate incentive to do it. It's not like it is 100 percent altruistic.

But in a price-based system where every time there's a high price you have to make a decision about what you want to do, like on a CPP rate, I think that the likelihood of just doing it is going to be less than if you have already made the commitment that when you're called you drop. It's because you don't know what your business situation is going to be at that point. You don't know, you know. A lot of manufacturing now is just in time. The cement industry does not maintain a lot of inventory because it's heavy, dusty and relatively low value.

ASSOCIATE MEMBER ROSENFELD: Barbara, wouldn't that mean that you would be worried about making a commitment as an interruptible customer?

DR. BARKOVICH: The commitments for an interruptible customer. You don't have -- Let's take the average -- Under the BIP program the BIP period is four hours, okay, and you can't have more than one of those a day. In the case of CPP in San Diego it's a seven hour CPP period. That's a lot longer period out of a working day than a four hour period.

The answer is, on an interruptible basis they know that they can sustain, you know, four hours. Whether or not they can sustain seven hours multiple days in a row isn't clear. All I'm saying is that if you have made that commitment you have adjusted your operations to be able to make it. But whether -- If it's a volitional thing where you are being told there's a higher price and you have an order that you've got to respond to. I'm just saying, it requires a different kind of assessment than having already made the commitment.

I am not saying 100 percent what they are going to do because I don't think they know what they are going to do. But I am just saying that they have made the commitment thus far. They have adapted their operations, made the investments, et cetera, in order to be able to interrupt. And because the decision has been made in advance they don't have to sit there and think about whether they want to buy through that particular set of hours. It's basically a zero-one decision that's already been made. So I have to make that speech so I have now made it. It is very important to my clients.

One of the concerns I have with respect to going to more price-based demand response, in particular in the ISO context, is something that came up earlier today. Andy made a comment and I think it was Andrew who said he was happy that this was going to be recovered on a transcript so we could check it out. And that is, the ISO has said that if utilities have price-based demand response programs that they can communicate to the ISO their expectations of some degree of load drop so that the ISO wouldn't necessarily over-procure in RUC.

That's fine. I think that there are still two issues there. One of the issues is, until we have an extensive track record, knowing when you have a price-based program, how much demand response you are going to get so that you can feel a degree of confidence in terms of saying to the ISO, we expect so many megawatts.

And then as Phil Pettingill said, the ISO has a tendency to de-rate the results. And so we have to make sure that there is a really clear chain of communication in terms of price-based programs so that there's as good an assessment as possible of what the demand response is going to be under a price situation so we don't over-procure in the forward market, in RUC, the residual unit commitment. We don't want to do that.

The nice thing about whether it is the interruptible program where you have a pretty reliable response because people get grave penalties if they don't participate, or something like auto-DR where the price response is technology-enabled, as I think that -- It is really scary when TURN and I are in agreement on these things. I think you have a better sense of knowing how much you're going to get.

I mean, I happen to think auto-DRs are really a great program for two reasons. One is it is technology-enabled so you have a better ability to kind of lock in on what the demand response is, even though it can be price stimulated. Still, when something happens the EMS system kicks off and you get a load drop and that load drop is measurable.

The other thing about it is that -- And this is something that I think Jim Bushnell commented on. It is such a brilliant comment but we tend not to think about it. And that is that with something like auto-DR, if you have it on a whole bunch of buildings and you are working towards getting a five or ten percent adjustment.

And you have heard me say this before, I apologize. They can stay in business. If you have a ten percent reduction and you can turn out some lights or you have a ten percent reduction, you may have to raise your thermostat. But that is different from a process industry response where by and large you are either operating a chunk of machinery or not. It's just different.

So if what we are going for is a five percent or a ten percent across-the-board reduction then having it be technology-enabled and having it done in such a way that it may -- there may be a comfort issue. And I am not denying that. And it depends on how much give there is in the system. Still you could do that maybe across a lot of load as opposed to a couple of big loads and actually be able to keep the economy going, which would be nice.

As far as my particular clients go, I think they can live with CPP or RTP. It makes it harder to plan. There are clearly volatility issues. That doesn't mean that they are crazy about them. They put a lot of effort into adjusting the time of use rates over the years. There is equipment that if you turn it on on-peak you get fired, you know. They kind of know what the rules are and they have adapted all their systems to it. And to that matter, for the 30 minute notice period for interruptions. So they have got that one down pat.

I would suggest, and I am almost finished, that an issue that came up yesterday -- early this morning. Sorry, it's been a long day.

ASSOCIATE MEMBER ROSENFELD: It seems like yesterday. (Laughter)

DR. BARKOVICH: Yes, right.

An issue that came up that really is important, and Phil said this and I've said this to you before. And that is, when the system is stressed it doesn't mean prices go up. Now why is that? I know we have got a balancing market so obviously the question is going to be, when we have a day-ahead market with presumably a lot more participation than in the current balancing market we need to really look at whether when the system gets stressed prices go up. If they don't there's a problem. There's sure a problem with RTP based on day-ahead hourly prices.

And again, the balancing market is only five percent of the market right now. People can hedge their positions, et cetera. But we need to be pretty clear that when -- if we are talking about getting price signals that are directly related to the wholesale market that in fact the prices go up when the market, the system is stressed.

If not, if we go to administratively-based scarcity pricing in order to get something to happen it suggests that something is not quite right. And we ought to be studying that in order to understand exactly what is going on in the market with the pricing mechanisms.

And I think that's probably about all I have to say so thank you very much.

ASSOCIATE MEMBER ROSENFELD: Questions from the panel? I'm sorry, from the dais.

Thanks, Barbara.

MR. ROBERTS: I am Bill Roberts; I represent the Building Owners and Managers Association. Most all of our members operate high-rise, tenant-occupied commercial buildings and they have all been on time of use rates for, I guess, decades now.

In response to those prices they have made major investments in efficiency improvements over the years. Many of these buildings we would show you efficiency improvements in 20 to 30 percent in both energy and load over the past five or ten years. So they have learned to live with time of use prices.

We became involved in rate proceedings just about three years ago because the members were feeling that there was just too much emphasis on non-coincident demand charges. We stepped into it and looked at -- Having not been involved we verified the old axiom that if you are not at the table you are on the menu. (Laughter)

Certainly that proved out to be the case. Many of our members were getting hit with 30 to 50 percent of their bill in the summertime in demand charges. So we have been actively involved in working on that.

But as we thought about rates we became much more interested in real-time pricing with the notion that I picked up somewhere in my career that electric prices should be cost-based, reflect the true cost of production and delivery. So we looked at RTP with the notion that there would be at some point relatively soon a market that would give us the true value of electricity as we go forward. Hopefully that is going to happen fairly soon.

So we have been one of the few parties involved in these rate proceedings who have been actually promoting the idea of real-time pricing. We see real-time pricing as a more granular version of the time of use pricing and putting our fortunes in the impartial market versus the administered prices that we were hoping to get away from. That's kind of the basis of our, of our interest in RTP.

From many of the calculations we have made over the past several years and different kinds of assumptions we have found that even though our members are very peaky customers they typically will come out better than they would under most other rate structures.

We also feel that RTP provides us with essentially the ultimate cost-tracking rate. Any other, any other rate that you might propose is going to compromise efficiency relative to what you get out of RTP. Economic efficiency, I should say. So we have been proponents for that. From what Andy had to say today I am pleased that at least it is still on the table, even though critical peak pricing seems to be getting a preference here.

In terms of looking at RTP versus critical peak pricing for commercial buildings. We don't see that there is going to be much of any demand response achieved from critical peak pricing, But we think that we have to look at the long-term in commercial buildings for how do we take advantage of efficiency and load management for a long-term reduction in demand and not an instant or short-term, a very short-term change as a result of the critical peak pricing prices.

We don't see that there is an incentive built into that structure, that rate structure, that would provide a compelling investment case for building owners to make the adjustment in the control equipment and possibly thermal storage and so on and so forth to be able to be responsive. But over time as the patterns of real-time pricing become apparent they will adjust as they have to the time of use pricing and make those investments.

It is critical that we think in terms of the incentive structure for inducing the investments that are necessary to make these responses. Because under the rules of leases and so on, building owners simply can't just cut back as the designers of critical peak prices might envision. It just isn't going to happen. The lawyers in these buildings would be on their cases instantly and so on and so forth.

There are many reasons that we would favor the long-term perspective. Help to reduce the -- Change the load shape permanently and not worry about the band-aid from one day to the next.

I guess that's about the extent of what I have got to say. And Andy has heard this over and over again, I'm sure.

ASSOCIATE MEMBER ROSENFELD: Well I do have some questions for you.

MR. ROBERTS: Yes.

ASSOCIATE MEMBER ROSENFELD: The PIER program here is supporting experiments with auto-DR in large buildings.

MR. ROBERTS: Yes.

ASSOCIATE MEMBER ROSENFELD: They are very enthusiastic and they say their collaborators are very enthusiastic. And I think the last 20 buildings I saw some data on were, in fact, saving 13 percent of peak or something on hot afternoons. I am not sure where you get your data that there won't be any response.

MR. ROBERTS: Well the difference is that all of those buildings, that I am aware of, were owner-occupied or government buildings versus being tenant-occupied buildings. Now that we have got the approval of sub-metering over time that issue will modify somewhat because there is now the potential of the tenants becoming involved in that process. So my concerns there may diminish as we gradually get that off the ground but that's going to take awhile.

ASSOCIATE MEMBER ROSENFELD: But that is something where we can work together.

MR. ROBERTS: Yes, oh yes.

ASSOCIATE MEMBER ROSENFELD: You can try

to do the metering and the contracting.

MR. ROBERTS: Indeed, yes.

ASSOCIATE MEMBER ROSENFELD: I guess you are happy that the chart that Andy showed, starting in 2010 I think the words real-time pricing appeared as frequently as -- 2011.

MR. ROBERTS: As long as it's an option we are happy.

ASSOCIATE MEMBER ROSENFELD: Yes it was, I believe.

And then in terms of the security of making investments in dimming lighting or setting up your thermostat or whatever. I would think there would actually be more security in critical peak pricing where there are published tariffs. And you would know more and you would feel secure about your investments than relying on real-time pricing, which depends on some market with unpredictable forecasting.

MR. ROBERTS: The CPP is unpredictable in terms of the number of days, when it is going to happen, and it is only for a few hours and so on. The arithmetic just isn't there for a stimulating investment. But at any rate we have been certainly in favor of RTP as an extension of what we are used to.

ASSOCIATE MEMBER ROSENFELD: Well that's certainly our privilege.

MR. ROBERTS: Right, right.

ASSOCIATE MEMBER ROSENFELD: Commissioner Chong.

CPUC COMMISSIONER CHONG: You mentioned that the way the lease structures run between the landlord and the tenants in these large commercial buildings posed some issues. Could you at a high level just give me a couple of examples of that.

MR. ROBERTS: I am not that close to the exact terms but there are temperature tolerance levels that are specified in leases and so on. It becomes a legal issue then between the tenant and the building owner if they don't fulfill those requirements. So that's something they have to live with.

ASSOCIATE MEMBER ROSENFELD: Could I weigh in on that too? I guess there is a problem with your present leases and that is, I don't know whether the number is one percent of real-time or half a percent of real-time. But it seems as if leases should move in the direction of saying, we guarantee to keep you in the comfort zone 99 percent of the time. But there are emergencies and there are shortages.

I think we learned from the statewide pilot, that's residential, that people are actually more than happy to participate in a real crisis for things that they just wouldn't be interested in doing every afternoon. And your leases don't take that into account.

MR. ROBERTS: There is no question that during the periods we have had the fear of blackouts and so on that the buildings have done everything they could possibly do and tenants have allowed them to do it. But if you are going to talk about a 12 event year and so on and so forth I think you are going to have a good deal of opposition to that.

ASSOCIATE MEMBER ROSENFELD: Yes. I think a compromise statement would be that maybe 12 times a year is a lot but one time a year is too little. And we ought to be able to figure out somehow or other in leases for something that isn't as rigid as 100 percent of the time.

MR. ROBERTS: Right.

ASSOCIATE MEMBER ROSENFELD: Other questions or comments? Thank you.

MR. ROBERTS: You're welcome.

MS. LEE: Well the disadvantage of going last is that everything that you wanted to say has already been said; but the advantage being that you get to say the last word.

Before I go into the substance I should -- something that I neglected to elaborate on was that DRA that I am representing is actually an independently budgeted and operated unit that is housed within CPUC. So just to be clear on that.

Regarding time-varying pricing. Our message would be that unless it is voluntary it is likely, surely to lead to customer confusion.

ASSOCIATE MEMBER ROSENFELD: To customer what?

MS. LEE: Confusion.

ASSOCIATE MEMBER ROSENFELD: Confusion.

MS. LEE: Bill confusion. And we all value customer education. But if educations are to be done they ought to start with how bills are calculated now, rather than forcing a customer onto a default rate structure that is different from the current rate structure and then explain, this is -- oops, this is how you have been changed from this one rate to the next.

DRA does support PTR as a transitional tool. We see the dilemma created by this program. The value we see it in it is that it does introduce the concept of time-varying cost of electricity.

And going back on default rates. Moving customers to default time-bearing rates. Our fear is that doing so could result in large-scale customer dissatisfaction, especially among mid- or low-usage customers whose load is driven by air conditioning load. Customers who will likely see a large bill impact. And even if those are not 100 percent of those customers, if only a small percentage, that could poison the public perception of time-bearing rates. So this is a caution that, of course, we are all aware of, I am simply reiterating.

DRA does support a rate structure that facilitates energy conservation, energy-efficiency, then demand response.

And one very last thing is that -- I thought about whether I should bring this up. But DRA does support AB 1X. And regardless of the life span of AB 1X DRA supports a rate structure that is conducive to energy conservation and demand response and low-income objectives.

When AB 1X expires we do support a gradual transition if there were to be a transition between rate structures, such that customers are not exposed to rate shock or confusion that would lead to wide scale dissatisfaction.

I guess that is all I have to say.

ASSOCIATE MEMBER ROSENFELD: I am going to bring up a touchy subject here. Because you talk about PTR as being acceptable, as if it is not forcing people to do anything, whereas critical peak pricing is an increase in price on a hot afternoon. And I am sort of looking at Ed Fong when I say this. Hello, Ed.

MS. LEE: PTR --

ASSOCIATE MEMBER ROSENFELD: Let me just make the basic point and then Ed and you can respond. I think PTR is a superb case of marketing. And it does get around AB 1X because people think they are being given something on a hot afternoon.

That money didn't come from nowhere. It comes from a price increase all the rest of the hours of the year. Except people are unaware of it because it is all the rest of the hours of the year. And I support it. I think it is a good way to get around AB 1X. But I am a little surprised that you at DRA think it is some sort of magic.

MS. LEE: It is not magic. We see it as being fraught with problems and we have proposed.

ASSOCIATE MEMBER ROSENFELD: You see it as being? I just didn't hear you.

MS. LEE: We do see it as a conundrum and we support it as a transitional solution to a situation that we cannot do anything about because AB 1X is the law.

DRA has proposed the two tier incentive structure that is in SDG&E's approved PTR program. We have proposed that as a way to minimize free ridership, which we are concerned as being a very serious problem with PTR programs.

ASSOCIATE MEMBER ROSENFELD: Ed won't let -- I mean Dave won't let Ed put his -- I can't resist. Ed Fong, what are you going to say about this? (Laughter)

MR. FONG: I think two points to be made. DRA and San Diego obviously reached a settlement agreement and that was what was authorized in our GRC Phase 2, which was the peak time rebate.

The first thing is true. I think most of the parties who support PTR view it as a transition rate. So let's understand that.

The second question that Commissioner Chong and Chairperson Pfannenstiel raised this morning, whether you could have a voluntary dynamic rate of some sort. I'll call it a more pure dynamic rate and a PTR at the same time. I actually had to think about what transpired during the settlement negotiations without revealing stuff because I think that's confidential.

What turned out to be the case, and SDG&E thought about it, is that we have a slight tension going here. If you have a voluntary incentive program like a PTR and a voluntary CPP, they're competing against one another.

And you have to, at some point in time -- and I think we talked about this in one session, Commissioner Rosenfeld. You have to find a way to ramp down PTR and ramp up a voluntary. You can't have them both at the same time at sort of -- the PTR at rather good incentive levels and just sort of a mild CPP because nobody then would volunteer for the mild CPP.

So when we talk about transition this is the issue. This tricky issue. I am not quite sure at what point we end up proposing the transition, this is the more difficult issue. When do you ramp down PTR and when do you ramp up other dynamic rate programs for the residential customer.

I think that addresses some of the question that you have here.

ASSOCIATE MEMBER ROSENFELD: Okay. So your opinion is it's a transitional, best we can do, given AB 1X.

MR. FONG: Yes.

ASSOCIATE MEMBER ROSENFELD: All right.

Other questions or comments from the panel? I'm sorry, from the dais. Tim Tutt.

ADVISOR TUTT: Just one in terms of default rates and ensuing customer confusion. It is true that the customers can opt-out as they get confused or don't like the rates, right? And does that resolve some of the problem for you?

MS. LEE: Regardless whether it's default with customers being opt-out and regardless whether it be a mandatory rate structure I think there is a political reality to electric service, such that it is a basic, essential service. In fact, the PU Code does specify that the Commission shall designate a baseline quantity to supply customers' reasonable energy needs.

If customers are not happy with their bills then they could react. And if the objective is to implement dynamic rates then I think regardless whether or not a party is forced dynamic rates I don't think large-scale customer dissatisfaction is a scenario that we would like.

ADVISOR TUTT: I guess I am left wondering if we happened to be on dynamic rates and were proposing moving to a five tiered rate structure as a default for customers whether there would also be customer dissatisfaction about moving to that structure.

MS. LEE: That's fair enough. But the five tiered rates didn't suddenly jump out of the ground and say, here I am. At one point California had two tiered rates. The tiered structure came about -- And I think Andrew Bell of PG&E can elaborate on this more, much more comprehensively than I can. But the two tiered rate that existed when the energy crisis occurred has telescoped since then into a five tiered rate.

And that telescoping was a result of the ever-increasing revenue requirement that kept on growing. And in order to recover the growing revenue requirement the rates had to be telescoped out in order -- such that more revenue can be collected.

That's the evolution of the problem and that is how it came to be. And understand, this is not, we are not oblivious to the conundrum created by the sharp differential between Tier 1 and Tier 5 rates.

MR. NAHIJIAN: Can I elaborate on that?

ASSOCIATE MEMBER ROSENFELD: Sure.

MR. NAHIJIAN: Thank you. Just in terms of default versus opt-in. I think that there's been some basic assumptions here. And the basic assumption is sort of like a 20/80 rule. You know, if you put in a default rate 20 percent of the customers don't have enough energy and enough interest in stuff like that to actually opt out. And so you have a remaining 80 percent.

And sort of the opposite has been true and that's what we were discussing in the SPP when that was going on. That if you have a voluntary rate maybe 20 percent will go in there.

The 80 percent though doesn't, I think, represent, you know, a decision on all customers based on perfect information as most economists would like to use as an assumption for everything. Because a lot of those customers just simply don't know. They simply won't know whether or not they are saving money, whether or not they are worse off. And probably about 25 percent of those customers don't even know what a kilowatt hour is. So you have to sort of -- They don't even know the units, they don't understand what it is.

And education is absolutely wonderful. You guys have been talking about that. It is certainly necessary if you are going to go into dynamic pricing. But you can only do so much customer education. As you say, you can lead a ratepayer to a demand response program but you can't make him reduce load. I mean, a lot of times they just don't know.

I think that's one of the problems in that again also with customer education -- Again I am going to point to a limited ability to be able to educate all the customers. And with all due respect to my good friends at the utilities, if you are going to depend upon their marketing programs or their marketing department, you might want to throw in a little extra. Because these are monopolies and they don't need to know marketing. They simply have been there forever. They are not good marketers like other people that have to deal with things in the private sector.

ASSOCIATE MEMBER ROSENFELD: I'll let the rest of the dais make a comment. But I think what is coming through here is that I at least think that some mild respect to price as a function of time is a good idea. And so I am for change. I think you feel that price response is a dangerous idea and you are less enthusiastic about change. But let's see what the other members of the dais think.

MR. NAHIJIAN: That has certainly been accused of TURN before.

ASSOCIATE MEMBER ROSENFELD: No comment?

DR. HUNGERFORD: If everyone on the panel is finished then we can move straight to the Public Comment section of our, of our agenda. Gabe is going to set up the lectern briefly so that we can have people come to the microphone to make their public comments.

I would ask that any public comments, there are two things you need to do. One of them is give a business card to the court reporter, or a name and a name spelled out for them.

And the other is you need to keep your comments brief. About three minutes is the normal expectation. If the dais engages you in discussion of course that limit is -- yes, ma'am.

CPUC COMMISSIONER CHONG: I wanted to make you aware that I do need to leave at four o'clock for another engagement.

DR. HUNGERFORD: All right, thank you.

So we can begin the public comment. We can line up at the mic.

MR. BRAUN: Good afternoon. My name is Tony Braun. I am counsel to the California Municipal Utilities Association. I've sat in the back for the whole day and watched and learned a lot. I just had a couple of very brief observations and I don't want to keep you long.

When I looked at some of the testimony that was provided by the PG&E representatives, by Mr. House with respect to some of the business decisions and assumptions that public agencies make when making water infrastructure investment.

When I look at what I know about my own clients across the POU community and some of the diversity of their programs. When I hear Barbara talk about the manufacturing processes. I see a very broad array of issues to be dealt with.

And it seems like in order to maximize the benefit that we are going to get out of energy efficiency and demand response initiatives we need a fairly broad initiative that explores all these nooks and crannies. So I wonder if the word standards is really the appropriate way to go about capturing all these benefits.

I know you have heard it over and over again from the POU community that we are so diverse within our 45 members that one size fits all and one program doesn't work from one utility to the next.

But when I see the observations from the water agencies and from Barbara about her clients I think that probably spans across more than the POU community. So I just wonder if developing standards, which I view as sort of hard and fast rules, is the appropriate way to tackle some of these challenges and move this ball forward. That was just observation number one from sitting in for the day.

Observation two is, I spend much more time, unfortunately, going over wholesale market rules. And I deal on these types of initiatives. And I would share Barbara's observations about the head scratching that goes on about how prices are derived in the wholesale market. And part of that is currently the market design, which is different than where we are going. But part of it is it's somewhat of a black box that produces prices and it is very difficult to get behind that and take a look at it.

And I would urge you, if we are really going to explore real-time pricing as an option for direct customer pricing, that we are going to have to explore how those real-time prices are derived. So I would say that if real-time pricing is a major part of this initiative we ought to have a workshop on how those prices are going to be derived.

And certain of the issues that I just wrote down very quickly while sitting in the back of the room are, the capacity obligations that are part of the wholesale market rules. How those are derived and how the costs are allocated. Those would affect the end-use customer prices that are, that are born.

Scarcity pricing issues, which the ISO is just now tackling.

The unit commitment deadline and the day-ahead market, which we have already heard about today.

The aggregation of the locational prices which are paid to generators but then aggregated to wholesale customers.

Market power mitigation rules that can dampen wholesale prices appropriately. Certainly in many instances when there are situations where market power tests are triggered.

So all of these things go into how wholesale prices are derived. And if the idea is to try to reflect that directly in a customer price I think we are going to have to spend a lot more time understanding those wholesale market rules before we advisedly move in that direction. Thank you.

ASSOCIATE MEMBER ROSENFELD: I have a small question about your first point about standards, before you go. Do standards mean tariffs to you?

MR. BRAUN: Not necessarily. Not necessarily tariffs as much as -- To me standards means mandatory rules. If I were using something that was voluntary I might pick words like guidelines, recommendations, reporting requirements, things like that.

ASSOCIATE MEMBER ROSENFELD: But in the language of today where utilities do have to adopt published tariffs is this an argument that they shouldn't -- Does this just boil down to an argument that you don't want mandatory tariffs, you want a broad selection of tariffs?

MR. BRAUN: Help me with that, Commissioner. Tariffs issued by the Commission, tariffs within each individual utility?

ASSOCIATE MEMBER ROSENFELD: The utilities propose tariffs, which are adopted by the Commission. I think Commissioner Chong is going to bail me out.

CPUC COMMISSIONER CHONG: Yes, the PUC authorizes particular rates to be charged by the utilities and those are typically referred to as specific tariffs. So I join the confusion of Commissioner Rosenfeld in trying to understand what you mean precisely by standards.

MR. BRAUN: The rulemaking that we are in right now in this Commission is on load management standards. And that is the noun I was referring to. Our utilities have tariffs just like the ones that are promulgated by the Commission for the investor-owned utilities and the other CPUC jurisdictional entities. When I speak of standards I am speaking of what may be contemplated by the Energy Commission in this proceeding, load management standards.

ASSOCIATE MEMBER ROSENFELD: That clarifies things, okay. So you are really talking about the general proceeding. The ten workshops or seven workshops, and not about tariffs.

MR. BRAUN: What this proceeding may produce.

ADVISOR TUTT: I'd say that's why we are engaging in the proceeding and hoping that you come. I'm glad that you have come to provide public comment. We are interested in understanding what standards mean in the context of how this authority can work.

It doesn't necessarily mean, you know, you have to do a specific rate. Maybe, and this is just speculation. Maybe you should offer a specific rate and let the market then decide whether that rate is feasible in your service territory.

We would appreciate any written comments here discussing the issues of the diversity in POUs and customer base and what could possibly be used in this proceeding in standards to help things move along in the state.

MR. BRAUN: Thank you.

ASSOCIATE MEMBER ROSENFELD: Anybody else?

(No response)

DR. HUNGERFORD: Well everyone, thank you for coming and participating today. I want to especially thank the speakers who put together their presentations in a relatively short time frame. The future workshops will have better lead times on the specifics, I promise.

I do want to raise one issue. Next week's workshop will be on Thursday the 19th on enabling technologies. I do want to warn those of you traveling to town that Interstate 5 will be under construction in the downtown area and it will have a strong impact on both commuters from the Bay Area and especially folks coming from the airport.

So you both need to leave additional time and you probably should visit the website www.fixI-5.com. And it will give maps, some detour routs and ways to get downtown without getting caught in it and getting lost. Because it isn't easy to get to town from the airport if I-5 is not functioning.

ASSOCIATE MEMBER ROSENFELD: Listen, I'll tell you, David, the traffic is really bad. I nearly missed my train on Thursday night.

DR. HUNGERFORD: So that's just fair warning for those of you who will be traveling for next week's workshop.

And so we will move right on to closing comments from the Commissioners who are here and then we can end our day.

ASSOCIATE MEMBER ROSENFELD: Comments, Andy? Commissioner Chong? Tim?

CPUC COMMISSIONER CHONG: I want to thank everybody that came today and for your presentations, particularly, and your public comments.

We look forward to a vigorous debate over the PD that was sent out today. I don't know whether Andy purposefully sent it out before this meeting so he could talk about it but not be able to have any complaints about it. It has just been sent out. I don't know if he was that devious.

(Laughter)

CPUC COMMISSIONER CHONG: But anyway, thank you. I look forward to comments on that.

And I wanted to thank our hosts.

ADVISOR TUTT: Again I wanted to thank everybody for coming and to remind people that written comments, per the schedule, are due on the 17th. So we would appreciate getting further input in the proceeding on the rates issue. Thank you.

ASSOCIATE MEMBER ROSENFELD: Ed, I want to ask you a couple of questions so -- No, no. Just don't go away, let me catch you.

So finally, thanks very much for a very informative day. We'll see many of you Thursday, nine days from today.

(Whereupon, at 3:47 p.m., the Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 21st day of June, 2008.