COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                  )
                                   )
Preparation of the 2007       )    Docket No.
Integrated Energy Policy      )    06-IEP-1C
Report (2007 IEPR)            )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MAY 7, 2007

1:00 P.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

James D. Boyd (in audience)

Jeffrey Byron, Associate Member

John L. Geesman, Associate Member

PUC COMMISSIONERS PRESENT

Dian Grueneich

CEC ADVISORS PRESENT

Melissa Jones

Tim Tutt

CEC STAFF and CONTRACTORS PRESENT

Linda Kelly

John Sugar

Lorraine White

ALSO PRESENT

Kim Crossman, United States Environmental Protection Agency (US EPA)

Snuller Price, Energy and Environmental Economics, Inc. (E3)

Eric R. Wong, Cummins Power Generation, on behalf of the California Clean Distributed Generation Coalition (CCDGC)

Don Schoenbeck, Cogeneration Association of California and the Energy Producer and Users Coalition (CAC/EPUC)

ALSO PRESENT (CONTINUED)

Nora E. Sheriff, Cogeneration Association of California and the Energy Producer and Users Coalition (CAC/EPUC)

Susan M. Buller, Pacific Gas & Electric Company (PG&E)

Janice Lin, StrateGen Consulting, on behalf of VRB Power Systems

Keith Davidson, DE Solutions

Chuck Whitaker, BEW Engineering (BEW)

Joseph Heinzmann, FuelCell Energy

Les Guliasi, Pacific Gas & Electric Company (PG&E)

Fred Skillman, Pacific Gas & Electric Company (PG&E)

Andrew McAllister, California Center for Sustainable Energy (via telephone)

Gary Schoonyan, Southern California Edison

Ellen M. Petrill, Electric Power Research Institute

Bob Burt, Insulation Contractors Association

Bill Karambelas, FuelCell Energy

Jane Turnbull, League of Women Voters

Alex Kim, San Diego Gas & Electric, also representing SoCal Gas

I N D E X

I N D E X

P R O C E E D I N G S

1:07 p.m.

MR. SUGAR: Presiding today is Commissioner Jackalyne Pfannenstiel. We have both the Integrated Energy Policy Report Committee, the Electricity Committee, and joining us today is Commissioner Grueneich from the California Public Utilities Commission. Do you have any comments?

PRESIDING MEMBER PFANNENSTIEL: Thank you, John.

Good afternoon. I just want to thank people for joining us for this subject matter workshop. As John said it's a join proceeding between two of the Energy Commission's policy committees, the Integrated Energy Policy Report Committee, for which John is the Presiding Commissioner, and the Electricity Committee, for which Commissioner Byron is presiding. Commissioner Geesman sits on both of those committees. And we are delighted to have Commissioner Grueneich of the PUC here with us.

I think it is very important that we are looking at these issues jointly between the two commissions. We both have certain implementation and policy responsibilities and I think it is really a very, very strong signal that we are together in hearing from the staff and from the parties in these matters.

With that, Commissioner Byron, do you have any opening comments?

ASSOCIATE MEMBER BYRON: Thank you, yes. You know, having only been on the Commission here for less than a year it is very clear that there has been strong and consistent support in both the Integrated Energy Policy Reports and by my fellow commissioners for distributed generation. And I certainly want to echo and add my support for those recommendations. I am glad to see this workshop today and I thank the staff very much for putting it on. I thank Commissioner Grueneich for being here.

I was reminded that five years ago that I was before this Commission making a presentation on the DG strategic plan. So I understand very much the effort that it takes to be here and for your providing input. I want to let you all know that we appreciate that very much and we welcome it, that's why we're here.

We are seeing something interesting in the last couple of, number of months. I am beginning to see that there is new interest in, excuse me, new interest in distributed generation projects in publicly-owned utility service territories. And I think that is really intriguing given the lower rate structure and the competitive aspect of DG having to compete in those territories and it is beginning to work.

So I am very interested in making sure that we address some of those impediments that we're talking about and I hope that we get to those today. I note that our investor-owned utilities have had a rather mixed track record when it comes to distributed generation so let's get the issues out on the table and let's have a good, candid discussion around that today.

Thank you, John.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Grueneich, do you have any comments?

CPUC COMMISSIONER GRUENEICH: Thank you. Mainly I just want to say how pleased I am to be here and to thank both Chair Pfannenstiel as well as the other commissioners for inviting me to be here.

That we have really been working hard over the last couple of years to show that the two energy agencies in the state are working together trying to set common goals and really trying to identify where there are barriers that need to be overcome.

That I have been a strong supporter of distributed generation, combined heat and power, over my 30 years in the energy business. I believe that it is a very important tool in the tool chest that we have here in California, both to ensure that our energy supply is economic as well as to now meet our global warming goals.

We obviously have a number of cases going on at the PUC that are addressing some of these issues. I am particularly interested in understanding what are the issues or barriers that are not being addressed in those cases so that collectively we can understand what additional steps we need to be taking.

And then to the extent that anyone has any observations or thoughts on how our new law, AB 32, on global warming and the possibility of setting up the cap and trade system may impact some of the issues we are discussing today I'd be interested.

But we are collectively, again, between

the two commissions having a specific effort on AB 32. So if that's not an issue people are prepared to discuss today that's fine but we will be moving into a very new era, I think, as we implement AB 32. So I am interested in how that will affect us as we're looking at establishing some of the policies that we are addressing today. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Dian.

Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Thank you, Madam Chair, and thank you, Dian, for coming today. You have been one of the pioneers in this area since the state first got involved in promoting distributed generation in the late 1970s.

I think one of our critical tasks in the 2007 IEPR cycle is to try and bring a pretty strong dose of reality to the rhetoric that this subject area has either benefitted from or been burdened by from state policy makers over the course of the last 20 years.

I think we have held ourselves out to a much higher level of performance than we have actually been able to achieve. I think that there is an ongoing schizophrenia in state policy between what we say we want to do and what we actually allow to happen. That tension, I think, is embodied in full force in the draft decision in the CPUC's SRAC case.

And I don't want to, and traditionally the Energy Commission has avoided trying to second-guess rate making decisions. But I think that in reviewing the draft decision it is pretty clear that at least the administrative law judge is on a different page from the Energy Commission and its 2005 Integrated Energy Policy Report.

And I think that probably the most frustrating aspect of that to me was our efforts to promote a focus on the combined thermal load and electrical load and the efficiency benefits to be gained from that combined perspective seem to have been missed entirely in the draft decision.

It is not clear where the climate warriors were in reviewing some of the elements of the draft decision. So I think we have got a lot of work to do to try and bring the reality of state policy into adjustment with the rhetoric that we all like to engage in.

And I look forward to this cycle, Madam

Chair, in providing that.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Commissioner Geesman.

John, back to you.

MR. SUGAR: Thank you. Our first speaker is Ms. Kim Crossman from EPA. Would you care to use the podium here?

MS. CROSSMAN: I'd like to use this if it's okay.

Good afternoon. Thank you very much to all of the Commissioners who invited me here today and thank you very much to the California Clean Energy Stakeholders who I have the pleasure to visit with today.

My name is Kim Crossman. I am the team leader for the Environmental Protection Agency's combined heat and power partnership program and I am here to give a brief introduction to CHP. Why the EPA actively supports the deployment of clean, distributed generation such as CHP and some of the issues that are being faced right now in this very interesting time of change nationwide and epitomized in what is going on here in California.

So the EPA Combined Heat and Power Partnership is a voluntary program. We were formed to foster the use of highly efficient CHP as part of the EPA's suite of clean energy programs to address the environmental impacts of energy production and usage.

In the past five years or so we have worked on about 250 CHP projects with our partners all over the country for a grand total of 3500 new megawatts of CHP nationwide since 2001. These projects represent over 10 million tons of CO2 emissions reductions cumulatively during that time period.

Our program is fuel and technology neutral. We work with multiple types of CHP applications, multiple fuel types and in multiple areas all over the country. I would say that a lot of the time that we have been running we have not done a ton of work inside of California because we have got partners who are industry partners who have been successful in this state. But right at this moment California is making some decisions that will impact the ability to deploy new CHP here so I am happy to be here.

Combined heat and power. I was under the impression there might be other DG folks in the audience who are not CHP people so please forgive me if this is a little basic. Combined heat and power is a highly efficient energy system. It is located at or near a building or facility and it generates electrical and/or mechanical power and recovers waste heat for use. That's more of a topping cycle idea, there are other, you know. CHP is at least two useful outputs from one fuel input, really, when we come down to it.

So the benefits of CHP. And part of this presentation was based on my recent review of the latest and greatest version of AB 1613 where suddenly the words, environmentally beneficial, cost-effective, and technologically feasible came up over and over and over in our latest draft of that. So the benefits are that well-sited and sized systems reduce all pollutants, including greenhouse gas emissions.

Technically these are fully commercialized technologies and proven applications nationwide and worldwide. This is not new or emerging. And economically once again, where the systems are installed in the right spot in the right application we get powerful energy savings and we also have reliability benefits that can avoid the catastrophic losses associated with utility outages.

But then of course all benefit statements are dependant on a baseline, you know. It's better than what, is the question. So I'm going to talk a little bit about the environmental benefits.

This slide has been trotted out probably 1,000 times in the last five years, everywhere I go where we talk about CHP. And the idea here is that through using the waste heat from power gen we are going to be significantly more efficient. And in the case of this slide, have significant CO2 emissions reductions.

Part of that is in the efficiency of the system in general. You know, a 31 percent efficient grid versus a 70 percent efficient CHP system. Now this is broad, nationwide averages we're talking about here. Part of it is also the avoidance of transmission of distribution and the losses associated with that. So you combine both of those and we end up with CO2 emissions reductions.

Now California is really its whole own situation because CO2 performance is a combination of fuel and conversion efficiency. And from what I'm reading right now the CO_2 performance that's being discussed and implemented through legislation in various places here is talking about new, gas-fired, combined cycle central plants, central utility plants, and 80 percent efficient gas blowers. So we're not talking about beating a 31 percent efficient grid and an 80 percent efficient boiler, okay. It's a higher standard than that is what's being discussed.

The question is, can CHP do that? And the answer is, yes it can. In order to do so the systems need to be thermally base-loaded, sized correctly as has been discussed repeatedly through various legislation, sized to meet the thermal demand and however much power you produce to go with that, is what ends you up with the most efficient system where you can actually get the CO_2 emissions reductions.

In order to do that analysis, when the power is used on-site the benefits of the T&D losses, not incurring T&D losses, absolutely should be included in looking at the benefits of a distributed generation system. And then biomass-fueled CHP, regardless of system efficiency, will be an improvement over the carbon baseline that's being discussed. Fuel cell projects as well are very, very low in emissions just kind of automatically.

So the EPA/CHP partnership has been administering the Energy Star CHP awards for the last five years and those awards are identical to what is being proposed in California as a performance standard. We compare a CHP system to state of the art, combined cycle, central gen, gas-fired and an 80 percent efficient boiler. And lately we give them the T&D as long as they are using the power on-site. And we have found 22 winners over the last five years who applied for and were able to achieve this performance standard.

I'm sure there are many more in the country, they just haven't applied for awards at this time. But I guess the bottom line is we know that CHP can do this. And CalTech is an example of a plant in California that did achieve and exceed this emissions and efficiency standard and won an award from us in '04. So we administer these awards.

One of the things I'm touching on here

is that we have got some things to offer and I'm not going to labor over that but my program is here with some services.

Technologically feasible. All of these technologies, turbines, microturbines, engines, boilers, are fully commercial, proven, with over 95 percent availability. All of them are available from multiple manufacturers today. Fuel cells and gasifiers are in the process of becoming commercialized right now.

Some products are available. All of the heat recovery and thermal technologies are proven and available today. The controls and switch gear are proven and available today. So that is one of the advantages that CHP has as a front guard of distributed generation in terms of commercial status and cost competitiveness.

We do maintain catalogs with all of the current status of technologies and are about to publish a biomass catalog in a couple of weeks that will have all of those as well.

So technologically feasible. The thing is that CHP is not a technology. This is an application and we just need to put it where it makes sense, where it's actually thermally baseloaded, matched to the site and the size that the site needs. We have a strong CHP industry in California that has continued to operate through the ups and the downs of the policy environment that have been experienced here over the last probably 15 or 20 years at least.

And CHP is already in California. I don't know how long I want to spend on this because this actually comes from a CEC report so I imagine you all probably know this. But average plants in California, about ten megawatts is the average capacity size. Most of the installed capacity is greater than 20 megawatts. This is for very simple reasons that CHP becomes more cost-effective, cost-competitive with the larger systems. Smaller systems, higher costs to develop so that just leads to larger systems in general.

Most of the existing capacity is in industrial applications. Very small commercial and institutional is only about one-seventh of the installed capacity currently. But when you look at sites and the number of sites that are deployed right now more than two-thirds of the sites are in commercial and institutional applications today.

And we've got various sectors and size

ranges that have had success in doing this and it's schools and colleges and hospitals, waste water. You know, these classic, easy, low-hanging fruit applications and then some that are a bit of a stretch that are doing well in California in hotels and health clubs and nursing homes.

And a lot of those projects really came about in the last five years under the self-gen incentive program because the incentive that was provided there made the difference in terms of the hurdle rate for the investment.

So there's still a lot of technical potential in California. We would say that two-thirds of the opportunity is in commercial and institutional applications but we're talking about sites when we say that. There's still a substantial opportunity in industrial systems as well but a lot of the potential is in these smaller systems.

So cost-effectiveness is part of the test that I have seen in various pieces of legislation. And, you know, I think the message here is that CHP is generally installed to be as efficient as possible because that's where the investment makes sense. You know, you wouldn't be throwing away a portion of the system's production. You would size the system to utilize the maximum amount of power and heat from the system.

And typically the best investments have been, at least in the last five years, where you can offset retail power at the site and use all the power on the site. It just helps with the payback. That's not to say that there aren't substantial opportunities still in industrial applications where they would be producing excess power and looking -- well, where they could produce excess power if they had the ability to sell it. But low-hanging fruit, again, would be where you are using all your power and heat on-site.

One of my points I would like to make here is that the cost-effectiveness test is really up to the site at this point to decide. If they are investing in an on-site power and heat system the question of what their hurdle rate, you know, what this system has to do economically, from anything that I have ever seen, is up to the site to decide. You know, they may have a ten year investment criteria, they may have a two year investment criteria. And it depends on what problems it solves for them and whether they go ahead or not.

So what makes CHP possible in California even in a schizophrenic environment is that in general we do still have a favorable spark spread here. It's not ideal. Gas is high and the investments get more and more marginal and we see a slowdown. But essentially if you take into account the thermal, you know, we can generate power for about five cents with $8 gas. So that's you know, a two second version of CHP economics.

So market factors affect everything. And part of the problem actually is volatility, it's a huge piece of it, and uncertainty. And I don't think we can change that by waving a magic wand right now. That we are in a changing environment and it is very difficult for the private sector to make investment decisions in a changing environment.

But part of what helps about having clear policies in place is that demonstrates to those investors that even in a changing environment the powers that be support what they are trying to do and will lead them, are going to help them go in the right direction. So that is one of the benefits, even of small incentives or even of efforts such as this.

So market opportunities, I've already talked about this a little bit. There are a lot of emerging opportunities and if we are really looking for deployment, if and when there is some kind of a standard or some kind of a goal set up in the state to get more CHP. Going after it on a sector-specific basis is a good way to approach it and is one of the things my program does.

So the impact of enabling policies on cost-effectiveness and customer acceptance. You know, there's a couple of different classes of ways we can craft policies that help to get good CHP deployed. Incentives provide capital recovery, they reduce operating costs, they add revenues streams and they increase customer acceptance.

It's back to what I just mentioned. That even a small incentive to an end-user -- you know, there are other states where they're going to get $3,000 if they do this, you know, on a $500,000 system. But the effect on the customer of knowing that someone has said there is a public benefit to doing this project and we recognize that through a small incentive, or any incentive, it does help, even if it doesn't change the investment decision. You know, it doesn't reduce your payback by more than a few months.

Grants are fantastic and we did see a lot of CHP get deployed in the state while the self-gen incentive program was available for CHP projects. Gas incentives such as you currently have in place on the cogen transportation rate reduce operating costs throughout the life of the project and I found to be an excellent mechanism to help get these projects deployed, especially thermally base-loaded projects.

And then this potential for environmental revenue streams is really an emerging area that may really help projects a lot.

To go along with that we had talked about barriers and the other bundle of policies that are very, very important have to do with removing the unintended barriers and streamlined or simplified interconnection, output-based emission standards, fair and justifiable standby rates and having other sorts of policies recognize and reward the public benefits of clean DG when being considered are very, very important here.

In a lot of ways what they will do is provide an added level of certainty to the people who are trying to develop these projects. That there is not just this question of well okay, we've got this great project and it's got a five year payback and that works for you. And you're going to go forward with it except we can't quantify how much time or how much cost is going to be involved in getting your interconnection. It could be $10,000 in three months or it might be $2 million in two years, and you'll just have to wait and see. That is the kind of barrier that absolutely kills projects. And any kind of certainty we can add in there is very helpful.

I'm going to give a couple of examples of some of the incentives and how they actually affect people's ability to do a project. And this is an example of some cogen gas rates. One is from California and the other one is from New York State. And this is just, you know, we're modeling a system that's a 925 kW thermally baseloaded system at a hospital.

The PG&E gas transportation rate -- now these are from 2004 and I'm not sure I have the latest, greatest rate but what I am trying to show on the sensitivity will show up regardless.

The boiler transportation rate, the gas without a CHP system, 75 cents NMM BTU in summer, 99 cents in winter. The CHP transportation rate, 15 cents NMM BTU. So that boiler no longer needs any gas. You're paying for a CHP system that provides you with all of your thermal energy and an additional incremental amount of power on top of that.

So we can see, you know, what is the difference in terms of payback on a project. The bottom line is tracking on gas rates, And this was $4 low. This is definitely a few years old. I don't know if anyone expects a $4 gas rate any time again. But at the time I think we were at about $6 when we ran this analysis.

And, you know, basically with the CHP discount that curve flattens out. Your sensitivity to gas rate increases is much lower. And it's because you're offsetting purchased fuel for a boiler. So where you would have bought fuel for your boiler that would have gone up anyway at this point you're buying an incremental additional amount of CHP fuel at a lower rate. And this helps a lot in terms of that investor risk.

Key Span in New York State has also got a boiler, a CHP gas transmission rate in place and this one has even a larger impact. Now our overall project economics are looking a lot better in New York because believe it or not they actually have higher utility rates. So this is, you know, we're down in this range of two or three years or so on a payback with the cogen gas rate.

But once again we can see the effect here is to level off the risk. It's to reduce a little bit of the risk for the end user to reward the fuel efficiency. Because when it really comes down to it combined heat and power is a fuel efficiency measure, natural gas efficiency.

Environmental revenue streams, I'm going to cover this in about two minutes because this is completely emerging and I just want to point out the effect on a project economics of some of these revenue streams. And, you know, we could be talking about basic emissions programs. NOx trading, offsets, emission reduction credits. We can also be talking about portfolio standards and RECs. And in some places where CHP has been put into people's RPS they now have REC-like, tradable

-- I think they're calling them white tags in some places, the name is still emerging.

And we are about to publish a major report going through all of these types of environmental revenue streams and the impact they can have on projects. So we looked at both, you know, a renewable project, a landfill gas project, and a CHP plant. And baseline economics, you know, based on today's situation. You know, we've got about a six-and-a-half year payback on these systems. The cost to produce power on the systems, you know, ranging in the CHP systems to about six to seven cents or six to eight cents.

So the value of the revenue streams is really going to vary like crazy. Every state will be different, every single trading program will be different, it depends on what you're doing at the site. If you were by any chance shutting down an oil-fired boiler and putting in a gas-fired CHP system there's obviously a lot of potential upside there. But I think --

Let's just get to the bottom line. You know, emission reduction credits, you know, can range, they can be fairly high. These are, these are annual values. And this is based on a modeled, giant report and these are just the outcomes. When we get into things like the RECs and, you know, you see the impact on a landfill methane project of RECs is a massive $1.4 million potential. I think that's based on New Jersey or something.

But then even on the gas-fired CHP where it's recognized we're talking about some different, some environmental revenue streams. I would say that, you know, a $45,000 environmental revenue is not going to make or break a project. But what it does do is it tells the investor this is a recognized public benefit that we are willing to put our money behind. And therefore they can have more certainty in going forward.

So that is a quick run-through and I thank you all very much. And a thank you to the Commissioners for giving me this opportunity.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ms. Crossman.

Are there questions from the dais? Yes, Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Thank you for being here. In recent years we have seen a pretty aggressive return of standby rates and demand charges. You mentioned that you maintain a database of best practices. Would that database have information as to best or better practices regarding standby and demand charges?

MS. CROSSMAN: Yeah, we have sort of two different approaches to that. I maintain a database of exactly what's happening in every single state, so we've got that. That's the, you know, where are we now question.

But we also have a group that does nothing but work with utility commissions and with best practices. We have a fact sheet on our website that's updated with about five or six different major policies that help or hurt clean DG. We update that probably once a month, my colleague does. That tells us exactly, you know, here are some examples of what's happening and what's being done in all these states and even gives a compendium of where each state is right now. So all of that is available right now.

And we are also happy to work with people to just ad hoc provide any kind of information.

ASSOCIATE MEMBER GEESMAN: Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Other questions?

ASSOCIATE MEMBER BYRON: Excuse me, Madam Chairman.

PRESIDING MEMBER PFANNENSTIEL: Yes.

ASSOCIATE MEMBER BYRON: I just noticed that Commissioner Boyd may have snuck in here in the back momentarily. Commissioner, you have been a big proponent of DG for a long time. I know you may not be able to stay very long. Did you want to add anything while you were here?

COMMISSIONER BOYD (FROM THE AUDIENCE): No, I am just a big proponent of it.

(Laughter.)

ASSOCIATE MEMBER BYRON: Okay.

Kim, I'm really glad that you made all the effort to be here. And I noticed you flew out a day early too so you wouldn't, so you'd be here. I think you had a problem at the ARB when you came out recently.

I think it is really interesting that the EPA is involved in this activity and we talked briefly about this. Can you briefly describe why the EPA is spending taxpayer money on this issue.

MS. CROSSMAN: Well it's because we can

measure the emissions reductions associated with clean DG. I mean, there are a suite of reasons, a suite of public policy reasons why this kind of thing makes sense. And our colleagues over at the Department of Energy also spend money and time working on this because they care about, you know, load pockets and they care about other benefits to the grid and other things along those lines.

For EPA we are kind of a one trick pony agency. We care about emissions reductions and this is a big part of our global warming strategy in the agency. CHP is sustainable in the sense that it is cost-effective. It gets us the emissions reductions. And we can do that without causing too much heartache or headache. On a voluntary basis help people look at this and help them do it.

And then at the end of the year I can measure what that looks like in terms of a reduction and what it means in terms of cars taken off the road or acres of trees planted.

ASSOCIATE MEMBER BYRON: You had mentioned that you thought our policies were somewhat schizophrenic here in the state. Maybe they're paranoia based.

(Laughter.)

ASSOCIATE MEMBER BYRON: But I was wondering if you could give us a sense, with your perspective, of all the different states that you're working with. Is there one or two things in particular that we should be concentrating our efforts on to correct in California in order to open up distributed generation and CHP?

MS. CROSSMAN: I think that you're facing -- back to Commissioner Grueneich's mention of AB 32. I think you are facing an interesting moment where the criteria pollutant thought process, the current air regulation scheme and controlling greenhouse gas emissions, are not the same thing. And I think that there is going to be some challenges in terms of marrying up those types of regulations and how you actually reduce greenhouse gas emissions.

And I see that both of your agencies, commissions, as well as ARB are going to have a lot of work to do to figure out how to do that in a way that makes sense. And it is going to have a huge impact down the road. You know, I would say that because I'm from EPA. We're watching very closely and are very, very interested.

On just a straightforward side. If in fact clean distributed generation is a piece of the picture here I think the two things I would hope is that if efficiency has incentives and renewables have incentives and demand response have incentives in this state, and clean DG is recognized as another piece of the solution within those same bundles, I would hope that it would also be considered that it would be helpful to have incentives in place.

There's been great work done on, you know, in the past the standby issue was handled well. I would hope that there would be continuing through process given to that as well.

It's interesting, it's like things move in the right direction for a couple of years and then they just move right back. I think to grow and maintain an industry that can do this in the state. It would be helpful to have some kind of a clear direction. And that's more of a process answer than a, you know, prescription. A self-gen incentive program? Okay.

ASSOCIATE MEMBER BYRON: Thank you.

MS. CROSSMAN: You're welcome.

PRESIDING MEMBER PFANNENSTIEL: Thank

you very much. Thank you for both being here and for your very useful insights.

Now I turn it back to John.

MR. SUGAR: Thank you. And what I will do is in the interest of time present the conclusions of the roadmap so we can present discussion.

Again, we have blue cards at the back. Following this I'd like to go through and if you do have a blue card, if you'd like to speak, please put it out where I can get to it and then we can get those up to the Chairman to move discussion along.

The DG and cogeneration vision for 2020 in the roadmap report called for California's portfolio mix to be diversified with central generation, demand response, energy efficiency, distributed generation and cogen. The vision included a market that allows DG and cogeneration to compete with central plants on an equal footing and it foresaw that DG and cogeneration would provide over 25 percent of the state's peak demand.

For those of you who have read through the report you have seen that the forecast includes a change of technologies over time with photovoltaics growing significantly, combined heat and power increasing some. Over time DG technologies taking a larger portion of the total from large cogeneration projects.

In the vision customers would have multiple options including distributed generation and cogeneration as part of their resource strategies. DG and cogeneration would be integral to utility procurement, transmission and distribution planning and operations, and it foresaw a distributed generation industry that was robust, filling utility and customer needs.

Large cogeneration would be readily, would readily participate in the wholesale power market. There would be transparent, dynamic rates in place which would account for the environmental attributes of distributed generation, locational benefits and costs and time-dependant benefits of these technologies. The renewable portfolio standard would be satisfied without additional or the need for additional incentives and DG permitting would be efficient and environmentally responsible.

Now the overall strategies to attain

this vision that were in the report include supporting incentives in the near term, having a transition to new market mechanisms over the longer term, and then in the long term reducing remaining institutional barriers to distributed generation.

Near term incentives would include tax credits for capital expense for renewable and clean DG, continued self-generation incentive programs and emerging renewable program efforts, supporting renewable and clean DG systems with low-interest loans and providing value for environmental attributes in the near term including production tax credits for criteria pollutants and CO2 emission reductions.

The transition to new market mechanisms would include development of renewable and CHP-distributed generation, expanding it with a portfolio standard, establishing market mechanisms to allow DG to compete with central plants and traditional transmission and distribution, and creating access to emissions markets to include an appropriately valued DG and cogeneration.

Reducing remaining institutional barriers would include instituting an analytical framework for distributed generation and cogen for assessing the costs and the benefits, developing rate designs allowing distributed generation and cogen to be effectively integrated into the electric power system, promoting distributed generation through rules and standards development and instituting an environmentally responsible permitting process.

And then within that there were specifics into which I do not intend to go. And as soon as I find the escape button -- well maybe the simplest thing to do is just go to the end.

So to start off our first speaker is Snuller Price from E3 to discuss pricing.

CPUC COMMISSIONER GRUENEICH: Excuse me. I have a question about the staff report. Would this be appropriate?

I think you had it up on a slide a figure, at least in the staff report it's Figure 6 on page 25. It's the curve, the upward curve. On the left hand side I'm just -- I want to make sure I understand. Looking at the blue, the photovoltaics. That's the portion that would be covered under what we call our California Solar Initiative and previously A Million Solar Roofs.

MR. SUGAR: Yes.

CPUC COMMISSIONER GRUENEICH: Am I correct?

MR. SUGAR: I believe so.

CPUC COMMISSIONER GRUENEICH: Do we have a number then for looking at where we are now in our baseline to where the 2020 vision would be for essentially the non-solar portion of what the delta change would be? In other words I'm trying to figure out, you know, how much of a hill we need to go up. Do we have those numbers either in the report or if there would be an opportunity to have them provided?

MR. SUGAR: They are not in the report.

CPUC COMMISSIONER GRUENEICH: Okay.

MR. SUGAR: We can look those numbers up and get them to you.

CPUC COMMISSIONER GRUENEICH: Okay, great. Thanks.

MR. PRICE: Good afternoon, thanks for having me. In the next -- My name is Snuller Price. I'm a partner with Energy and Environmental Economics and I was asked to say a few things about the DG roadmap vision on the tariffs.

So I think as John laid out we are going to have a few topics. My goal is to spend five minutes or so to sort of give the group my reaction to what was in the DG roadmap for retail rates and tariffs and a quick reaction to it to sort of start discussion in this topic area.

I borrowed from one of the tables that you'll find in the report that talks about, what's the situation with the rate structures, at least in 2005, and then what is the vision for 2020?

In the roadmap the situation that's laid out is sort of the current situation for rates for DG are that energy prices are not transparent and they inhibit customer response to actual costs. That the current rate structure is based on sort of a controlled average pricing. It doesn't include locational environmental pieces. That it's difficult for DG to participate in the wholesale power markets and it's difficult for cogen to execute new contracts with utilities.

That's the situation as it's characterized. And then looking ahead to 2020 the goal is to make rate structures more transparent, connected to markets, take extra analities and internalize them in rates so that you can get credit for improvements in environmental impacts as well as T&D constraints, and to allow customers to more easily participate in the wholesale energy markets. That's just the quote, the table from the DG roadmap.

When I read through the DG roadmap I tried to take all that and sort of summarize it into, well what does this mean. This little diagram is, I think, what I got anyway, one vision of what's in there. And maybe during the discussion other people can have their input on what they thought it meant.

I think the idea is on the left hand side I've got adding different components together to get to the DG retail rate. There are dynamic prices perhaps from the MRTU that's coming up, there are some capacity costs, there are CO2 offsets or environment, and there are other components sort of bundled together, okay.

Because we've got dynamic prices in here we have some more intelligent metering, I'm thinking AMI. And I'm thinking that the meter is smart enough so that you can, you can go either way. So you can buy energy at a cost that's the sum of these things or you can sell. And if the market prices are right then you can buy or sell and you can go either way.

Now there are -- If you notice the rate there are sort of two categories. There are these sort of energy-related components, which is energy losses, as Kim had mentioned. Environment. There are sort of these energy-related costs and those are represented by the MRTU.

There is also generation capacity, transmission and distribution capacity and fixed costs that also need to be collected. And I'm going to talk a bit about that because I think that's going to be really the crux.

But the concept is, if you get all of these pieces right and all of the costs right then you can have a market where the owner of the DG is actually looking at what's there in terms of market signals and they can participate in the market by buying or selling. So think that's the vision looking ahead 2020 for what we could do with the retail rates.

Now how do we get there? And this was really intended to sort of kick off discussion. What are the issues that we have going from what we have now towards something that looks like this? And I think that the big one to me is how do we allocate fixed costs and rates? So it is very difficult to have your AMI meter there sitting there and be able to buy and sell at the same price all the time and still collect your fixed costs.

So how are we going to do that? And included in that I can include generation capacity, transmission and distribution capital costs. And then rate forms that have those costs that vary with, you know, how those costs are incurred are often and have long been considered anti-DG.

And everybody in this room knows the discussions there but fixed customer charges, demand charges, ratcheted demand charges. There are a lot of other ways to take and put fixed costs on those and to collect those. So I think that that's going to be a major issue in terms of how do you do the DG retail rates.

And then the second piece, which is related is, how do the distributed generators sell capacity back? What are the rules going to be for a distributed generator to be able to get a capacity payment and how are those going to be structured. You get into the issues of reliability, you get into issues of who controls the dispatch of the generator. You get into issues like physical assurance on how reliable is the generator in order to be able to get a credit back for your capacity piece.

And also with that I think that an important issue is that the opportunity sell back capacity depends a lot on where you're at. So if you're a generator that's going to be sited in a new development that's completely greenfield there might be a significant amount of capacity that you could sell and earn versus a constrained area, a load pocket where you could probably provide value to an unconstrained area where there really isn't a capacity constraint and you're not really going to get a local capacity value. So there's going to be big differences in terms of the value of DG by area.

So with those two lively issues I guess the last one that I sort of threw out there is applicability of the rates and whether or not we're talking about retail rates for just distributed generators or whether we're talking about rates for all customers, okay. So what's sort of the scope of the idea in terms of getting from here to there.

If we've got -- You could make an argument if we've got all the costs right and we've got the right incentives to invest in DG then why wouldn't we use that same rate to give customers the right incentive to buy into energy efficiency or into any other capital purchases? So why would they necessarily be DG rates? Of course when you broaden the scope you've got a lot of other issues about bill impacts for large numbers of customers, et cetera.

So those are the three sort of discussion items that I took away from looking at the DG roadmap.

And I think with that should I turn it back to --

PRESIDING MEMBER PFANNENSTIEL: Questions from the dais first.

MR. PRICE: Questions.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Snuller, I wonder if you could go back to, I think it was your second slide.

MR. PRICE: This one?

ASSOCIATE MEMBER GEESMAN: No. You were just on it.

MR. PRICE: Sorry.

ASSOCIATE MEMBER GEESMAN: That one. Could I rewrite that second bullet so that rather than rates signal customers it said, costs signal regulators to make the right choices about utility procurement. Because it seems to me that we authorize the utilities to procure electricity. The stuff that they're procuring today is pretty profoundly inefficient, pretty profoundly carbon-unfriendly or climate change unfriendly. They're doing it in all of our names.

We have had nominal policies for 25 years to promote a different way of looking at things. Our current system fails to properly integrate thermal loads with electrical loads. We've got this distorted policy configuration where we try and fit square pegs into round holes and pretend that every cogenerator or every distributed generator is a merchant power plant.

Shouldn't there be more of a burden on regulatory policy than the way you're second bullet frames it?

MR. PRICE: Perhaps. I guess the regulatory policy could be to develop the rates and so that you're trying to get all of the right economic signals in the rates and do that. Or perhaps what I'm kind of hearing from you is more of a portfolio-type approach where you're just asking for a particular, you know, a different mix of resources to be purchased.

And I think that's a choice, you can go either way. Either a portfolio approach where you're going to be, you know, by this type, you know. And depending on how, how scripted you want to be you could be very specific about what should be in that portfolio. Or you can be much broader in terms of, you know, let's set prices at cost and allow more flexibility.

I don't know if that makes sense to you.

ASSOCIATE MEMBER GEESMAN: I just wonder if we'd been a bit more consistent over the last couple of decades about encouraging this focus on efficiency in this effort to combine thermal and electrical loads would we find ourselves in the situation that we are today where the ISO suggests a massive increase in locational capacity requirements in Southern California. Or where the

CPUC directs Edison, go out and build peakers, build them fast, build them expensive.

It seems to me when we make choices like that every day or every year the notion that it's just a function of finding the right flavor of cheese to put in front of the mouse and then get the mouse to do what would be in the mouse's best interest to me seems an over-simplification.

But thank you for bearing with me.

PRESIDING MEMBER PFANNENSTIEL: You know in your last point in the issues down the road, what is your point of view? Do you think there should be DG-specific rates or rates that are designed according to the sort of principles that were inherent in what you're describing that then would be applicable to all customers?

MR. PRICE: The economist in me would love to say we should get the rates, you know, to be dynamic and reflect as closely as we can the real marginal costs. But, you know, I think that there are a lot of tradeoffs in rate design, complexity being one of them, understanding bill impacts.

And so I think it would be very difficult to get there with the rates that I'm talking -- the concept of the rates that I'm talking about for all customers. And maybe 2020 is a long time and maybe we could do that. But I think it's a pretty -- it's a lofty goal but I think difficult to get there.

PRESIDING MEMBER PFANNENSTIEL: But you would think that DG customers would be better able to handle those other, complexity and other public policy issues?

MR. PRICE: I think so.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

Any other questions?

Thank you very much.

MR. SUGAR: Our next speaker is Eric Wong from Cummins Power Systems.

MR. WONG: Good afternoon, my name is Eric Wong. I am here on behalf of the California Clean Distributed Generation Coalition, I serve as its chair. I am happy to address the joint panel of the Commissioners of the Energy Commission and the Public Utilities Commission.

What I've just handed out to you, I don't have a slide. I chose not to have a slide. Sometimes people get, especially after lunch they get a little bit glazed after looking at the screen for so long, I do. I am going to walk somewhat quickly through these.

What we have here is based upon our written comments which were submitted last week of the top seven concerns of the clean DG coalition. I'm going to do this in a reverse order, in a descending order, and I'm going to start with number seven and work my way down.

Number seven is, integrate CHP storage and renewable technologies. I'm actually checking some of my editorial comments here. It should be supported by both commissions and the Clean DG Coalition urges both commissions to support the demonstration of a micro-grid in California in 2007 or 2008.

And the reason for this is pretty straightforward. Micro-grids can increase the penetration of CHP and renewable technologies. And later today during a comment period one of the members of the coalition will be speaking more on storage technologies with you and how that can serve as a glue for CHP renewables and advanced storage technologies in micro-grid situations.

Number six, CHP should not be subject to non-bypassable charges and standby reservation charges. I think I'm going to be answering some of the questions that were posed by the panel of Commissioners earlier. In the context of being virtually identical to energy efficiency and demand side management resources the mini-grid environmental benefits and the state's pronouncement that CHP is a preferred resource, CHP should not be subject to such charges.

Number five, I'm going to get into incentives for CHP. I don't believe this has been brought before, before any of the commissions. Gas procurement for customer-sited CHP should be done by utilities on the same basis as is done by utilities for their own power plants.

One of the biggest challenges to customer-owned, customer-sited CHP is the volatility in gas prices. So what I am proposing here is something for brainstorming. I think this is something that we can certainly engage in as a colloquy of people here.

The next incentive I address is the SGIP, which has been talked about before. As many of you are following the legislative action on this, it has been stripped out of the SGIP bill, AB 1064. We would like to see it be reinstated somehow into, into the program for combustion-based combined to end-power.

The question earlier about what other states are doing in terms of incentive programs and I'm going to point you to Connecticut and their energy independence law of 2005. There are some excellent examples in that of various incentive payment programs. There are three that are worth noting. The one-time capacity payments to CHP for congestion relief, there is incentive payments to CHP that are part of resource adequacy, and lastly there is incentive payments to the utility for education and assistance programs to get CHP to participate in resource adequacy.

Number four, working my way down. CHP is a baseload resource providing reliable capacity and energy is indisputable and should be explicitly included in utilities' resource adequacy requirements and the long-term procurement process. The CEC has done several seminal reports quantifying the economic potential of CHP. Utility forecasts must assume a reasonable economic penetration of CHP over the playing horizon and explicitly include CHP megawatts as meeting resource adequacy requirements.

Number three, CHP's reduced carbon impact compared to central station power plants merits evaluation in tariffs and/or to be a commodity in greenhouse gas training programs. Natural gas combined cycle power plants have an efficiency range in the high 40s to the mid-50 percent. CHP units regularly exceed these ranges for central station power plants. Not only is CHP a far superior way of conserving natural gas resources but the carbon impact for greenhouse gasses is unmatchable. CHP therefore comports squarely with the state's greenhouse gas goals.

Number two, this is just a one-liner. The Coalition, the Clean DG Coalition seeks completion of the cost benefit methodology by the PUC in its rulemaking at the earliest practicable date. This proceeding began in 2004 and was suspended I believe in 2005. We would like to see that completed as soon as possible.

Item number one, my last point. A CHP portfolio standards should be adopted. A CHP portfolio standard by the state of California would elevate the importance of the technology in the eyes of the nation and other states. Greenpeace International and the American Council for an Energy Efficient Economy, excuse me, all strongly support CHP. The Sierra Club lists CHP in its portfolio of preferred resources for the transition to a clean energy future.

Long a leader on energy issues we urge the California Energy Commission and the Public Utilities Commission to lead once again.

That's the basis of my remarks, thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

Are there questions? Yes, Commissioner Grueneich.

CPUC COMMISSIONER GRUENEICH: You mentioned the Connecticut law. Do you have any information as to how it has been implemented? I think it says or your notes stated that it was passed in 2005. Do we have any information as far as any payments that have been made last year or this year to date and, you know, how well its doing?

MR. WONG: Commissioner Grueneich, I do

not have that at my fingertips. I'd be happy to provide that later.

CPUC COMMISSIONER GRUENEICH: Okay.

MR. WONG: I don't know if anyone --

CPUC COMMISSIONER GRUENEICH: Because, you know, it is very intriguing and it would be interesting to see if it is getting payments out there and then what that's doing in terms of getting actual projects developed.

I was also quite intrigued with your item seven and I read your comments on my train ride here this morning. In the specific comments it talked about suggesting that the PUC move expeditiously in the PIER program and other initiatives to have a micro-grid in operation at the earliest possible date. Can you give us any sense of what would be needed to, you know, if collectively we said that was a good use of the PIER money what it would take to make that happen?

MR. WONG: I can, there's two parts. Are you speaking just strictly for the PUC or both?

CPUC COMMISSIONER GRUENEICH: We don't, we don't run the PIER program. So it says, the PIER program and other initiatives so I'm fairly indifferent. I was looking at the PIER program. If there's a PUC initiative that would be pulling this together I'm interested in that as well.

MR. WONG: Right. From the PIER program I understand that the Energy Commission is moving fairly, I was going to say rapidly. But they're taking steps to have a micro-grid in California, a demonstration. I believe Navigant Consulting is doing this for the PIER program. And there may be someone else on the staff that can speak with a lot more detail on that.

I've been contacted, I'm sure they've contacted a lot of other industry people. Cummins Power Generation as well as other members of the Clean DG Coalition are fully capable of having a micro-grid work. The interesting or the most challenging part of it is having the power electronics to make sure our loads and resources are balanced and there's no back feeds into the utility distribution system.

Which leads us back to the other side of the coin, Commissioner Grueneich, and that is what the PUC must do, or at least consider, and that would be the over the fence from a resource, distributed generation resource is combined heat and power going across the street or over the fence. And that invokes I think it's Section 2185.5 of the PUC Code which talks about prohibitions about going beyond over the fence.

So you can do it to the left or right on the same side of the street but in a true micro-grid you may have a distribution feeder circuit that goes much farther than that. And the PUC would have to, at least in my opinion for the demonstration, waive that requirement.

CPUC COMMISSIONER GRUENEICH: I haven't dealt with it for a couple of years. My memory is that's in statute, the over the fence requirement. I know you're not a lawyer, not to put you on the spot, but I'm interested if any of my Energy Commission colleagues have a sense. In order to do a demonstration of a micro-grid do we perhaps collectively have to look at some exemption from the existing law?

ASSOCIATE MEMBER GEESMAN: I don't think we've identified that as a barrier to the PIER effort.

CPUC COMMISSIONER GRUENEICH: Okay.

ASSOCIATE MEMBER GEESMAN: We may very well need to dig into it further but I don't think that's been seen as an impediment.

CPUC COMMISSIONER GRUENEICH: Okay. So is it that we don't have any impediment or that there is? Again, you may not know. But if there is an impediment because of the over the fence restriction that would be one that the PUC could lift if it were done, closer working together on the PIER program between the Energy Commission and the PUC.

ASSOCIATE MEMBER GEESMAN: I think that's right, I think that's right.

CPUC COMMISSIONER GRUENEICH: Okay. Well let me just say on behalf of my agency, if there is anybody at the CEC who is working on the PIER program, because I am very interested in making sure that there is better coordination between the CEC and the PUC on the use of PIER monies, let me know if there is something we should be doing because we'll certainly step up to the plate if we can.

PRESIDING MEMBER PFANNENSTIEL: Anything else? Thank you very much.

MR. WONG: Thank you.

MR. SUGAR: Our next speaker Don Schoenbeck.

MR. SCHOENBECK: Good afternoon, I'm Don Schoenbeck. I'm here on behalf of CAC and EPUC. I do not have a slide presentation either. I was flying in from Boston last night and my flash drive crashed. So the presentation is gone but I do have a few points to make.

But first let me say who I am here on behalf of. The Cogeneration Association of California and the Energy Producer and Users Coalition is made up of very large industries. More specifically it includes the companies of British Petroleum, Chevron/Texaco, ConocoPhillips, Exxon and Shell. These are obviously companies that have a great deal of CHP already operating in the state. Collectively it's in excess of 1500 megawatts of CHP facilities.

I think much more important than that though is the additional potential these companies have to offer to the state. This potential is in excess of 1,000 megawatts. What you heard earlier from Kim Crossman is how important it is to do a thermal matching in the -- in sizing for CHP to maximize the benefit, to maximize the efficiency.

For my clients, to give you an example, if they would size their CHP facility to match their electrical load the resulting installation or system would be approximately 50 to 100 megawatts. On the other hand since they are so energy intensive, so thermally intensive, if they would size the CHP facility to match their thermal system it would be in the range of 200 to 500 megawatts.

Now everyone would agree that it's much more efficient to build a larger system. You get far more greenhouse gas reductions, you get a much more reliable system. But there is a risk that comes with building the thermally matched system and that's to get sufficient revenue to pay back the capital cost and the operating cost of this much larger system.

So that's effectively the essence of my talk is that for CHP, the CHP industry, size matters. As the projects get larger the effective heat rates get smaller. For our clients if they would do a 50 to 75 megawatt installation the effective electric heat rate would be in the range of 11,000 BTUs per kilowatt hour.

To the extent they can build a combined cycle plant with the technology in excess of 250 megawatts that heat rate would go down to 7,000 just on an electrical basis. Once you acknowledge the thermal credits from the steam load you get effective heat rates much closer to the 5,000 BTU per kilowatt hour range for a new repower of an existing CHP facility.

What this means, since we all know in greenhouse emissions the amount of emissions you could add is directly correlated, the amount of fuel that's burned. To the extent you can put in a more efficient CHP system the whole state is better off.

Now the roadmap report for the most part focuses on distributed generation and uses a somewhat arbitrary cutoff line that it be connected to the distribution system or that it be less than 20 megawatts. I'd like to simply point out that with respect to the size that it's really an arbitrary value.

And if you look at transmission customers on the utility systems in this state for both PG&E and SCE where they have collectively in the range of 300 transmission customers their average size load on the transmission system is less than four megawatts for PG&E and just five to six megawatts for SCE.

So to say that just because you're connected to the transmission system does not necessarily mean you're going to be a 20 megawatt project or larger if you want to achieve your goal of trying to gain 5400 megawatts that the roadmap says is your target by the year 2020.

So what do you need to do in this state to actually get there? We think, in fact, that you do need to incent CHP facilities and there are several things that need to be done. First of all you have to create a sink, that is a must-take obligation, for the surplus power that goes beyond the needs of the site. This is absolutely required.

What goes hand in hand with that is also that the revenue streams be assured from the surplus power and that the contract have a term that's sufficient enough to recover the capital costs of these very expensive installations. And I think you saw in Ms. Crossman's chart how the payback period for these systems at very high gas prices is many years out into the future. So you need a contract for ten years that can provide an assured revenue stream so it can be financable and built.

Just as important I think the revenue stream should reflect the local, occasional benefits from transmission and distribution, capital expenditures, as well as any cost or credit of any greenhouse gas or environmentally regulated obligation.

In at least one instance one of our clients was almost successful in being a winning participant in a utility RFO but for the fact that the utility would not allow any pass-through of additional environmental rules and the associated costs, should they occur, during the term of that contract. So it's very important that any such costs, such as a carbon tax that comes into being, can be passed through in these types of contracts.

I think just as important there needs to be no NBCs or non-bypassable charges assessed to the load. This is a state where ever since the energy crisis it has been proposing such charges and that needs to be relooked at and we'd certainly recommend the NBCs be dropped.

And finally there is another part of the roadmap that talks in terms of for larger cogens they should be able to participate in the market.

I can stand before you today and say

these are some of the most sophisticated companies. But when it comes down to the operational level they don't want to be market participants. They simply want to run their core business, be able to sell -- be able to have the utility take the surplus power that they do not need and go about their business. So therefore we think the utilities should continue to be the scheduling coordinator and be the interface between their entity and the ISO.

So those are my thoughts and thank you very much for allowing me to appear before you today.

PRESIDING MEMBER PFANNENSTIEL: Thank you for coming and sharing your thoughts with us. Are there questions from here? Yes.

CPUC COMMISSIONER GRUENEICH: What is the approximate current amount of large cogeneration in California?

MR. SCHOENBECK: If you're talking about -- the numbers I have are a little bit different than what Ms. Crossman showed. I have about 150 megawatts of generation that's come through the SGIP program. With respect to the contractual cogeneration that SCE has and PG&E has that's more in the range of 4,000 megawatts for just those utilities. So in other words, Commissioner Grueneich, I don't have a statewide number.

CPUC COMMISSIONER GRUENEICH: Because, again, I'm on the chart in the staff report, Table 7, which breaks out the 2020 vision. And it shows for large, total large generation under division in 2020 will be 11,200 megawatts. So I was just wondering if you had a number that will compare to what we have now.

MR. SCHOENBECK: The number I have as of January 2007 was for the SGIP program. It's for just about 150 megawatts from 284 contracts. And this is where I do not have a statewide figure.

CPUC COMMISSIONER GRUENEICH: Okay.

MR. SCHOENBECK: For just PG&E and SCE I have 4,625 megawatts of CHP for just those two investor-owned utilities.

PRESIDING MEMBER PFANNENSTIEL: Go up to the microphone if you'd like to comment.

MS. SHERIFF: Nora Sheriff, also on behalf of CAC and EPUC. My understanding is that the existing, large cogeneration facilities, that is as they have been defined, facilities above 20 megawatts, 8,155 megawatts. So the 2020 vision statement sees a goal of an additional 3,045 megawatts for large cogeneration facilities.

CPUC COMMISSIONER GRUENEICH: Thank you.

MR. SCHOENBECK: And I just say that's defined as the over-20 in another 2,000 megawatts of the under-20 so you get to the 5400 for combined CHP. And of course in our view every megawatt of CHP is good, whether it's from a one megawatt facility or a 500 megawatt facility.

That's why we feel they all should be in the load right after the demand reduction programs and the energy efficiency programs. They should basically be the first resource of choice.

CPUC COMMISSIONER GRUENEICH: And I have one other question to follow up on my opening remarks. That if we do end up developing a cap and trade system under AB 32 in California in theory there is an economic value.

And I'm focusing again specifically in the large cogeneration projects because of the increased efficiency and therefore the carbon emission offsets. At least in theory there will be a market that will develop and there will be traders who will come in and provide both economic value and the ability to be marketing those emission offsets.

Is that something that is seen by the clients that you deal with, the members of your organization, that holds some promise in the future for promoting? Again I am focusing on the large cogeneration. Or is it viewed as the market is just not going to provide the type of certainty that's needed and a more traditional command and control would be appropriate for providing the incentives. Do you have any thoughts one way or another of how we essentially start to layer in AB 32 in a cap and trade world into some of these policies?

MR. SCHOENBECK: Well I may not be the best person to answer this but I'll certainly give my perspective. I think with respect to the RECs there is obviously a possibility there. You saw, again, from Ms. Crossman's slide there is a significant financial potential impact.

I think in general what we have heard, and actually in talking with some of the CPUC staff on the very issue of how RECs should be handled we took the position that as long as the cost and the credits are equally considered we would not have a problem with that type of approach. But certainly the RECs should be considered as part of a program because they are, they could be a financial, a significant amount of financial money.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

I think now the idea is to see if there is discussion specifically on this section. I have one blue card for somebody who asked to speak on the section on the tariffs and that is Susan Buller from PG&E.

MS. BULLER: Is this mic on?

PRESIDING MEMBER PFANNENSTIEL: The green light needs to be illuminated.

MS. BULLER: Can you hear me? Can you hear me now? Okay. Hi, I'm Susan Buller from PG&E and I wanted to applaud the California Energy Commission on a couple of topics.

First of all to just put this report forward because this is a very timely area that a lot of people are looking at and it is time to pay some thoughtful attention to that and I appreciate it happening now.

The second thing is, and following on some of the things that the prior speaker was talking about, PG&E, I appreciate him queuing up the size issue because it has been PG&E's position for quite some time that we could use a lot of clarity around the issue of size of distributed generation. And I appreciate the fact that the report in fact called that out and did take some steps in that direction and we applaud the CEC for that reason.

PG&E would like to point out that there are some things, for example, interconnection issues that can be dramatically simplified for smaller DG but can't be for larger DG. And that there are more sophisticated customers when you're looking at a larger DG unit that you may not expect to find when you're trying to penetrate the smaller customer market with smaller distributed generation units.

So there are all kinds of physical and policy and safety and reliability and political reasons why you are going to want to have separate policies for separate sizes. And PG&E in fact would suggest that there might be three levels you would want to look at.

And whether it's distribution versus transmission or whether it's over 10 or under 10 or over 20 or under 20 I don't think that's nearly as important as having a certain amount of clarity just so people understand and know.

But we would also like to introduce the idea of yet a third size that could be considered some kind of micro-distributed generation because we think both the California Energy Commission, the Legislature and the CPUC have already led the way along that by having various policies that cut off at one megawatt or 1.5 megawatt or 5 megawatts for the various existing subsidies that are already in place. And so we would encourage the idea of maybe a tri-level set of clarity around distributed generation.

The second point I wanted to talk about was the fact that there are various subsidies, as we all know, that exist for distributed generation today. Most of them are based on various size issues. And that I'd like to underscore something that the gentleman from Cummins Engineering called for, which is some closure at the CPUC about the benefit cost analysis that should precede, PG&E believes, any additional subsidies that are received by cogeneration.

The third point I wanted to make was to

address the fact there's discussion in the report, there's discussion in a lot of previous reports, I've been here before and listened to members of the cogeneration community talking about what the market barriers are. And I would just like to call for the Commission to address market barriers appropriately. That you do not overcome a market barrier that needs to have an educational element added to it by simply throwing more money at it.

That if the issue is customers don't understand something then the response is education. If the issue is customers have difficulty with the Cal-ISO tariff then the solution is to address the Cal-ISO tariff, not just to just indiscriminately raise incentives for customers.

What you will eventually do when you do that is end up having a counterproductive thing where you are incenting exactly not the sort of combined heat and power you want. So I am basically just expressing a call for identifying what the market barriers are and then addressing those.

And then the final point I wanted to call to -- and I think everyone is on board with this idea. But clean, when we talk about clean we really need to be clear about what that means. And at a minimum PG&E would suggest that combined heat and power or distributed generation not be considered clean unless it is at least as environmentally beneficial as the alternative would be.

Are there any questions about any of the four points that I --

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: I'd actually commend you for the way you framed that. We might come to some different conclusions, I suspect, than you do but --

MS. BULLER: What a surprise.

ASSOCIATE MEMBER GEESMAN: In terms of what the alternative would be, what are you thinking of there?

MS. BULLER: What I'm thinking of in -- And I'm not an engineer so boy am I going to blow it here. What I'm thinking of is what is the next conventional power source that would be brought on line. So I think what I'm talking about, and anyone from any one of the utilities or even anyone from the DG community can correct this, is a combined-cycle. And if you're looking at CHP you're thinking about in conjunction with a boiler. And you look at the relative efficiency of a combined-cycle, today's combined-cycle with a boiler and compare that with the proposed CHP.

ASSOCIATE MEMBER GEESMAN: But you're thinking the alternative should be a new plant as opposed to displacing some of the old jalopies that we currently rely upon.

MS. BULLER: Correct.

ASSOCIATE MEMBER GEESMAN: Okay. I wonder how you would feel if given your company's knowledge of your customers and historic commitment to service to your customers' needs if we imposed the requirement on you and said, you have to procure X amount of DG over the next period of time and we set some criteria for what that DG was to look like and left the details in your hands. Wouldn't that be more efficient than trying to figure out the right flavor cheese?

MS. BULLER: Well, until I see the cheese it's going to be very hard for me to answer that because it's a relatively hypothetical question.

ASSOCIATE MEMBER GEESMAN: Less so than you might imagine.

(Laughter.)

MS. BULLER: You're probably right.

PG&E supports distributed generation as one of the choices that our customers ought to have available to them. PG&E has supported most of the legislation. I want to say all but I am not absolutely certain, most of the legislation in recent years. We supported the California Solar Initiative. We're working very, very hard to improve our interconnection process for our customers.

We're working very hard to implement the SGIP program and the California Solar Initiative and we're very proud of both of those efforts and we have supported most legislation. And in fact without actually having looked at, you know, until I see language I can't say for sure but PG&E probably would support the extension of the SGIP program, the continuation of it, to support CHP.

ASSOCIATE MEMBER GEESMAN: I see your ads here, you're also a big supporter of the renewable portfolio standard.

MS. BULLER: Correct.

ASSOCIATE MEMBER GEESMAN: Is this any different than really just a subset or add-on to the renewable portfolio standard?

MS. BULLER: It is and it isn't. At some point you have to take into account that you want to deliver cost effective energy to your customers. So you at all times are going to be balancing customers who can participate with customers who can't.

ASSOCIATE MEMBER GEESMAN: Seventy-five out of 80 of the renewable portfolio standard contracts have come in below the market price reference so that program seems pretty well buffered against non-cost effective expenditures.

MS. BULLER: That is not my area of expertise. I'm aware of the fact that so far it has come in. I am also aware that the next one is not going to be as easy. I mean, there was a certain amount because of the newness of the program, a certain amount of low-hanging fruit. I'm not sure how long that is going to be available.

Now I've just completely stopped my brain. Ask me another question, John.

ASSOCIATE MEMBER GEESMAN: Let me come

back to what you think the benchmark should be.

MS. BULLER: Okay.

ASSOCIATE MEMBER GEESMAN: This new combined cycle. That's the same as we use in the market price reference, isn't it?

MS. BULLER: I think so, yes.

ASSOCIATE MEMBER GEESMAN: So it would seem a logical extension then of that program design.

MS. BULLER: I think as long as you are focusing on whether something is cost-effective you are not going to go too far wrong.

ASSOCIATE MEMBER GEESMAN: Thank you.

ASSOCIATE MEMBER BYRON: If I may, Ms. Buller.

MS. BULLER: Sure.

ASSOCIATE MEMBER BYRON: One of the recommendations that was put forward by Eric Wong I had not seen before and I was just wondering if maybe you had a response on behalf of your utility. Gas procurement for customer-sited CHP should be done by utilities on the same basis as is done by utilities for their own options provided to CHP. Is that something that might be workable?

MS. BULLER: That's something that I don't know enough about, gas procurement, to be ready to answer but what I could do is get back to you.

ASSOCIATE MEMBER BYRON: Okay. Well, I can appreciate --

MS. BULLER: Or Les could get back to you.

ASSOCIATE MEMBER BYRON: I can appreciate you don't, you don't have the ability to answer.

MS. BULLER: Right.

ASSOCIATE MEMBER BYRON: But theoretically wouldn't it make sense that that would be the same sort of, that they could have the same sort of advantage that your existing generating capacity does with regard to gas procurement?

MS. BULLER: And again I am not, I don't know enough about how PG&E does gas procurement to know what the pluses and minuses of doing it on behalf of our customers would be. I think that's what the recommendation was and I am not sure how the market would play out or what the impact would be. It sounds reasonable but that's not the same thing as sure. I am not in a position to say sure today on that point.

ASSOCIATE MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

Are there others who have given me blue cards who would like to speak on this subject of tariffs and charges? Then come on up.

MS. LIN: Good afternoon. My name is Janice Lin, I am the managing partner of StrateGen Consulting. We're a strategic consulting firm that advises renewable energy and clean DG clients. And I am here on behalf of VRB Power Systems, which is an advanced energy storage manufacturer and member of the California Clean Coalition and member of the Solar Energy Industries Association.

I have just a few slides and I'll try to go through it quickly because I know you have a full agenda. Thanks very much for allowing me to make some remarks today.

The first thing I'd like to do is just mention that the subject of what I'd like to comment on is why advanced energy storage should be an integral component of California's DG policy roadmap. I read through the document and noticed it wasn't explicitly in there.

Advanced energy storage, let me define that by suggesting it's a class of energy storage technologies that are commercially available today that weren't necessarily commercially available five years ago and represent scalability from serving as small as residential customers up to large industrial customers, have a very long life span commensurate with renewables with solar and can be discharged on a daily basis. So lots of duty cycles.

Many California DG projects are photovoltaics. My background specifically was in photovoltaics. And as we all know, during summer the California peak is highly coincident with solar. However, peak load isn't fully shaped during the late afternoon when solar output begins to decline.

This is what, this is a typical day in the summer of Cal-ISO and this is what the curve would look like as a result of the implementation of the CSI. And what I'd like to show you is what the same curve would look like hypothetically if we had five kilowatt hours of storage installed for every kilowatt of solar. And what you see here is a pretty dramatic flattening of the system-wide peak. The net impact is there would be more energy usage at night but less peak demand during the day.

In fact, energy storage systems can be implemented alongside solar, distributed wind and other DG technologies such as combined heat and power. It can be a useful vessel to capture excess electricity. For example, from combined heat and power. It can also be installed on a stand-alone basis and the usage would be basically to charge every night, discharge during the day on peak.

The reason I think that we are partnered with the California Clean DG Coalition and the Solar Energy Industries Association is that one of the great benefits of storage with these distributed technologies is it has the ability to improve the value proposition for those technologies. For example in the case of solar it enables the end-user to capture demand charges all throughout the peak window, which may be as late as seven or eight o'clock at night.

So some of the benefits of using

advanced energy storage to reduce peak demand include system energy costs to the extent that there is lower cost marginal power that can be procured at night, stored and discharged during the day. There is definitely a cost savings.

Air quality. At the California Energy Commission's electricity and air quality conference last fall it was stated that shifting power demand off-peak can reduce the use of older, dirtier peaking plants and result in better air quality.

There is a system infrastructure benefit in that the existing T&D infrastructure can be better utilized, have a better load factor. In fact, advanced energy storage is pretty dispatchable on demand so it can be used as alternative to spending reserve.

And then finally with respect to distributed systems. There is other value streams that an end-use customer can capture such as the better, greater ability to participate in DR programs, the ability to have UPS and backup capability as well. And as was discussed by Snu and others, the magnitude of these benefits will depend on where the system is sited, the available tariff, et cetera.

There are a number of energy storage systems that are commercially available today. Here is a full list from the Energy Storage Association. These two types here, there's several types of flow batteries and a sodium-sulfur battery that are commercially available and these two classes of storage technologies are probably well-suited for distributed application.

Advanced energy storage can be sited for any size. In the example of vanadium redox flow batteries, capacity and power are independent of one another. The battery can be as small as five kW and up to ten megawatts on the capacity side. And the duration, the number of hours of storage, really depends on the tank size. So that builds in tremendous flexibility into the system at any one customer.

Here is a case study of a customer in PG&E territory. This is the Santa Rita Jail in Alameda County. And what I wanted to show you, this is a cloudy spring day. For those of you who may not be aware of this, Santa Rita Jail already has a megawatt of solar installed on its rooftop. And what you're seeing here is a load profile, and this is modeled off of real data, that shows what would be the impact of advanced energy storage at this large, municipal customer.

The net result would be their load to PG&E would be the sum of the yellow plus this blue bit. This is where the battery will be charging. The aquamarine is the solar system discharging during the middle of the day and then the battery discharging alongside the solar. So the net load profile of this customer, it's no longer a peak, it's a trough in the middle of the day. Imagine if there were hundreds of customers all over California of this size that had this load shape that also had dispatchable power by Cal-ISO.

As you can imagine with every new or emerging technology, and I would say storage is in the early commercialization period, it's not the lowest cost technology available out there. It's in the same set of technologies as fuel cells and solar.

And when we looked at where would be a good home for this technology within the California programs we felt that advanced energy storage met all of the self-generation incentive program requirements. It has a large market potential. It has significant and reliable on-peak demand reduction potential. It has a very long equipment life commensurate with solar and photovoltaics. Financial assistance is required.

It's practical and safe to install. There's plenty of systems installed worldwide to demonstrate its safety and efficacy. The technology has zero emissions and it can comply with the current program requirements with basically changes to four paragraphs in the handbook. And the important thing to underscore is that unlike other eligible peak load reduction technologies, advanced energy storage is dispatchable and can provide system control benefits from a central location.

So in closure I'd just like to encourage all of you to consider the introduction of advanced energy storage into California's DG policy roadmap. There's lots of places that storage can be used throughout California's electric infrastructure at substations and substation backup applications. That would be utility application for T&D asset optimization. There's lots of examples there. This is primarily a utility application as well.

But we're particularly excited about distributed customer sited applications because that is where there is the greatest opportunity to capitalize on many different value streams and solve a number of problems that end users face. And then, of course, storage can also be used on energy farms, wholesale wind and solar plants.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

CPUC COMMISSIONER GRUENEICH: Thank you very much. Do you feel that this technology is captured within the series of recommendations that are included within the staff report or are there additional recommendations that you would suggest that would need to be made in order to ensure development of advanced energy storage?

MS. LIN: Well, I think that certainly the staff report commented intensively about the benefits and the need for peak load reduction. And advanced energy storage I don't believe was specifically cited in the report nor is it specifically cited as an eligible, sort of a distributed generation technology.

And I know in some of the PUC filings

they are starting to define distributed generation a little more broadly as a class of distributed energy resources of which energy storage is key. So I would encourage that to considering broadening the definition and thinking about including this technology in some of the incentive programs going forward.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

Is there anybody else who has given me a blue card who would like to speak to this subject specifically?

MR. DAVIDSON: Hi, I'm Keith Davidson with DE Solution, an engineering consulting organization that primarily caters to the combined heat and power community. We're a member of the California Clean DG Coalition and we also, you know, work with a number of manufacturers and equipment suppliers to the combined heat and power industry.

I wanted to echo a couple of other, a couple of comments that have previously been made. One of them by John Schoenbeck with, you know, on the non-bypassable surcharges that combined heat and power users get saddled with.

And I also want to go back to some comments that Kim made about combined heat and power as efficiency. It's the most efficient way you can use natural gas. It affords many, many of the same benefits that you get from energy efficiency or renewables. It's a much nearer term technology and we feel that combined heat and power, just like energy efficiency, just like demand response, just like if a customer decides they want to shut down part of their operation, that those measures should not be saddled with non-bypassable surcharges such as is placed on combined heat and power.

And I'm not really an expert on some of the net metering rates but my understanding of the net metering rates that apply basically to renewables, and I think also natural gas fuel cells below one megawatt, that they also are exempt from non-bypassable surcharges for electricity that they generate. Please correct me if I'm wrong. So that's one comment.

The second comment I wanted to make had to deal with the importance of the incentive, continuation of the incentive for combined heat and power. There's a -- You know, and I agree with Susan that, you know, that there ought to be, you know, we ought to be focused on, you know, on cost-effectiveness and economics.

But I submit that there is a different rate of return or a different set of economics that are applied from the utility and from the PUC perspective than from a small commercial business or a small industrial would use to invest their own money into what they would call a non-core investment.

And that there is definitely, you know, probably a two, maybe a three-year payback gap that exists between what a lot of end users are willing and can justify paying and what is, you know, and what utilities justify as prudent for their expenditures. So we look at the incentive as one mechanism that kind of bridges that gap.

And as Kim pointed out, there's incentives for energy efficiency, there's incentives for demand response, there's incentives for renewables. And I don't, I don't, I can't come up with a reason why there shouldn't be a continuation of incentives for combined heat and power. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Should we move to the next subject.

MS. WHITE: Commissioner, I just wanted to make an announcement in response to Commissioner Grueneich's questions on the micro-grid. Thursday's workshop, it's an IEPR-related workshop on the distribution system planning. We'll actually be discussing the PIER work on the micro-grid. And that is currently scheduled for the afternoon on Thursday.

And Linda Kelly, if there's any specific questions about the scope of that discussion is available to answer any questions. But I just wanted to let everyone know that the distribution system workshop Thursday we'll be discussing the micro-grid topic.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Lorraine.

MS. WHITE: You're welcome.

PRESIDING MEMBER PFANNENSTIEL: John.

MR. SUGAR: Just wondered if there was anyone on the telephone who have expressed interest in speaking to this? No.

PRESIDING MEMBER PFANNENSTIEL: So we'll move on to the discussion of interconnection issues.

MR. WHITAKER: Well good afternoon. I am also very happy to be here to speak to the Commissioners on the topic of Rule 21, which has in our estimation been a very valuable success. In particular successful coordination between the Energy Commission and the PUC in achieving some goals that were established a while ago and coming to some fruition on those.

I want to start out by talking about the current list of participants in Rule 21. This was a recently reestablished list that Chuck Solt, one of our colleagues on the project, had gotten from those who have been on the mailing list for a long period of time who said yes, we do want to continue being involved in Rule 21.

So you can see there's a variety of participants, both in terms of the numbers of organizations and in the individuals involved in that. One hundred thirty people feel it was important to be at least kept informed of what is going on in the process. Seventy-one different organizations representing the broad variety of the industry.

We also have our support team and I wanted to at least recognize those folks and the team that were not able to be here today. Chuck Solt is here with Lyndh & Associates. I'm actually here speaking for Jose Palomo who had other obligations today and he is the CEC staff person who has been leading this for the past year. Before him Dave Michel and of course Scott Tomashefsky who started off the project. Reflective has been the prime contractor on this and we've been working with him along with a number of other contractors in maintaining the forward progress of the activities.

Some time ago Scott Tomashefsky wrote his guiding principles on how we should move forward on developing Rule 21 and these are presented here. That basically what we develop should be very clear and transparent in terms of who has written it and what it's intended to be applied to.

The rules were intended to be technology neutral except when differences are fully justified. And I'd like to take this point to raise the issue of sizist endeavors. You will notice in Rule 21 that kilowatts or megawatts rarely enters into the discussion because it turns out it's rarely the issue of concern. It's usually something like current or voltage level or various other things.

And kilowatts tends to be a convenience that people use but it's really not the issue. And so I would suggest, being an engineer, that if you do need to come up with criteria for establishing demarcations that it be tied to a specific issue. At least if those demarcations are technically oriented. And that's a goal that we have strived to maintain in the rule.

The rules are supposed to be uniform throughout the state and I think at this point, at least among the three IOUs and many of the munis that have adopted some or all of the Rule 21 requirements, that they are fairly uniform.

And the last goal was that the utilities be compensated for any, for any services that they have to provide to support DG.

So in terms of accomplishments that we've achieved since the process started in 2000 we have a literally consensus-based interconnection rules. It's been adopted by the three IOUs and a number of the munis, as I mentioned.

Based on a cost effectiveness study that was performed a year or so or two years ago we have an estimated reduction in the cost of interconnection per interconnection of about $6400. And the time to interconnect has gone down from just under a year to a little over three months. So fairly significant reductions in both the time and cost for this process.

The work group has done a number of technical and policy-related activities. We have published what we call a supplemental review guideline, which is a series of technical requirements or guidance for the utility protection engineers on how to apply, what issues to address when our initial review process is not, is somehow exceeded.

And that has been very useful in a process of basically training both sides of the issues here, the utilities and the DG providers and the manufacturers. What the various issues are and how those issues can be addressed. So we've tried to bring those things to light in the supplemental review guideline.

We also have an interconnection guidebook which is almost the soccer mom's version of Rule 21. Not exactly but it's intended to be more for the user who is trying to apply Rule 21 and what kinds of issues they will run into and how they go through that process.

We have had a very active coordination process and involvement in the development of relevant IEEE and UL standards. And that has been also I think a key success and our participation has been very much underscoring what's going on in those areas. We also had a very successful monitoring program where we monitored a number of DG systems and have quite a mountain of data showing the performance and the actual -- essentially the lack of impact that these DG had on the system during their operation.

We have a -- Under Rule 21 we have developed a certification process to simplify moving forward with various DG projects. Especially for the smaller systems it makes a lot of sense to have the equipment tested in advance so that they don't have to be tested in each application. And right now we have about a dozen different products on the Rule 21 list.

And we have a very, as I mentioned a very effective working group. We have met 78 times over the I think it's actually seven-plus years that the process has been, has been going on. Many times in this very room.

The current issues that we're looking at, we have issues with multiple tariffs and combined technologies and this has recently been resolved from the policy group. On the technical side, which I actually represent and help facilitate the technical part of the working group, we have a number of ongoing issues that we've been working on.

We recently resolved or have been working secondary spot networks as a key issue and that was part of a report that was published last year. The request from the PUC in terms of specific activities that we should undertake. And that report basically said that we need to continue evaluating this issue. We actually developed some ideas. Those ideas are being implemented in IEEE right now but that's still an ongoing process in terms of network systems.

One of the issues that has just come up, and this gets back to the sizes issue, people want to apply Rule 21 on transmission interconnection. And there's reasons to do that and there's reasons why you have to be careful about doing that. So we have that as a task right now, to see how that might actually go about at least in terms of the technical requirements and how you apply those rules that we've developed for Rule 21.

We have some revisions to do. IEEE has continued to develop a number of standards and we have some revisions to do to the document to accommodate what has occurred and what is now part of the IEEE series. And in particular we have some certification and test standards that we need to revise the document to take on.

And lastly here, this was a comment from Jose. That the PIER research objectives have been achieved and the CEC is now looking for a custodian to take on the process.

My personal perspective is that there is a number of things, especially on the technology side, that have people still interested in participating, still interested in having some organization that can continue to put these issues on the floor in front of both a group of utilities and DG providers in an open forum where we can discuss them. It has been a very effective tool for dealing with issues in the past, which certainly have been the simpler of the issues.

And those going forward will be probably more difficult and more in need of exactly this kind of forum to resolve.

And I think that is pretty much the end of my presentation. I have some additional slides here from a presentation I gave last week to the DER integration PAC. This just shows a series of IEEE standards that are currently under development to deal with DG interconnection and certification and various specific technical issues.

We have UL 1741, which is a test standard for equipment that has now been broadened to cover -- It started out, as many of these things started out interestingly, as PV standards for PV interconnection and have broadened themselves to cover all forms of DG. In particular this has utility compatibility and interconnection issues that it addresses.

And I think I'll go ahead and skip through these and see if you have any particular questions.

PRESIDING MEMBER PFANNENSTIEL: Are there questions? Melissa.

ADVISOR JONES: I have a question. In

what I have read about Rule 21 and heard about Rule 21 it is always characterized that the policy issues are actually determined by the Commissions and that this is a technical type of organization. Can you give me a flavor of what the kinds of policy issues you're referring to are?

MR. WHITAKER: Well, things like what sorts of rates should this entail. Let's see, how should -- A lot of, a lot of the technical issues like the combined. How do you deal with an application where he has a combined or a non-net-metered system and a net-metered system. It has an existing gas-fired DG and PV. The technical issues are pretty simple, you know. How you meter that, there's a number of technically easy ways to deal with that.

But the policy side is, well which do you consider first and how do you, how do you address that, that piece of the puzzle. All of the application forms, all of the contracts, a number of things. Someone help me here. What else is there?

SPEAKER IN AUDIENCE: Metering.

MR. WHITAKER: Metering.

SPEAKER IN AUDIENCE: Metering is a

policy issue.

MR. WHITAKER: Metering is a policy issue. The technical side can say, you know, this is how you wire it up but yeah, what gets metered, where you put the meter, what's included in the metering, those kinds of things.

ADVISOR JONES: Okay, thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions? Yes.

ASSOCIATE MEMBER BYRON: Mr. Whitaker, my recollection, and there's others maybe in the audience that have been involved in Rule 21 activities or at least following them longer than I have, was that seven or eight years ago the biggest concern or the biggest issue we were dealing with was safety around interconnection. At least that's what many of the IOUs, most of the IOUs were concerned about.

My sense is that we have addressed that and a number of other issues in Rule 21 to date, correct?

MR. WHITAKER: Well, I would characterize it this way. It's not as though there was a safety issue that is now solved. Safety is an underlying issue. It's the primary reason for all of the technical results that we have come up -- all the technical requirements deal with safety and reliability of the system. So it hasn't gone away. And it's not as though we have really eliminated technologies or applications, we've just moved forward in a way that everyone is comfortable with the safety aspects of those applications.

ASSOCIATE MEMBER BYRON: Okay. And my understanding is that about five years ago, maybe six years ago, there was an agreement with the PUC and the Energy Commission working collaboratively that we would, if you will, undertake this effort and fund it as well. And I think we have been doing that for the last five or six years.

What is your sense of how much work remains? Now I know you touched on this a little bit but I'm getting a lot of feedback from the investor-owned utilities that Rule 21 has run its course, that we don't need it any longer. What is your sense of what's left to be done and is there an ongoing need for this, for this group?

MR. WHITAKER: Well my answer is yes and in probably a different role. And I think if you sit in the meetings you do get the same sense.

There are a number of people who feel, you know, we've done our job, we had goals set out, establish consistent rules across the state meeting various requirements, addressing a majority of the issues. And from that perspective that job is done.

What we have done as a part of this process is develop a process whereby people can bring in issues. The technical side, the protection engineers, we can talk about something new at every meeting.

One of the things we have done recently in the past two years or so is gone to quarterly meetings, in part to reduce the burn rate on the contracts that the support folks have had. And that has really slowed down the work, especially on the technical side. Because, you know, most of what we have to do -- And it's the same on the policy side as well. You sit in a room and you argue about the issues and you discuss them and you learn what is going on and, you know, it's this learning process.

And with the quarterly meetings it has, it has really slowed down the participation on the technical side because you tend to lose interest.

When I brought this up at the previous meeting earlier this year everyone in the room, including the IOU engineers said, we should meet more often.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Grueneich.

CPUC COMMISSIONER GRUENEICH: You noted that there is this issue of funding to continue the Rule 21 working group after 2008. And I believe it's because the PIER, the current PIER money is ending. Is there any reason why there couldn't be an augmentation of the PIER money? Or is it a view of, the type of the work that will be done post-2008 is a wholly different matter so it wouldn't essentially come within the scope of activities that will be encompassed under PIER? Can you help me understand since this isn't an area I'm familiar with.

MR. WHITAKER: Yes. I think the issue has not grown new, it's grown a little bit more, it's grown a bit larger recently. And that is simply that PIER, the last letter is for research. So the question has been, how is this a research activity? And initially we had at least an adjunct project where we were doing some field monitoring that made the research part very comfortable. And that has been more and more difficult for people to address as we go on, how this constitutes research.

We are involved with the standards development side and a number of other things. There are a number of areas where there's not answers and where this group is very effective at providing input and guidance. Whether or not that's research, that's where the whole issue lies.

ASSOCIATE MEMBER BYRON: That's correct, Commissioner Grueneich. The difficulty is now justifying this as continued research funding out of PIER. And then of course the question is, are there ongoing needs for Rule 21 and does the PUC see needs for it as well as a forum for issue resolution around interconnection.

The other issues that might come up would be certification of new equipment and how would that process continue. And I believe there's also this concern about keeping the investor-owned utilities within the state from bifurcating the interconnection process. In other words this keeps it consistent throughout the state. Is that a fair read?

MR. WHITAKER: That's a very fair read. In fact, many of our most contentious things have been trying to, you know, to herd the cats and keep everyone on the same path. Maybe that's a mis-characterization but all of the utilities have different systems and different perspectives. And having them in a room, you know, trying to fight to a single goal has been a very interesting set of issues. And I think you do run the risk that if they are allowed off on their own that you will not necessarily come all to a common conclusion.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Yes.

MS. KELLY: My name is Linda Kelly, I'm from PIER. I work in the distribution and distributed energy resource program. I just wanted to just clarify and support what Chuck said.

PIER has been very supportive of this work. And I think now the key thing is that we have continued funding to make a smooth transition that I think we would like to see happen where as we gradually move, I think further and further away from some of the research issues, we still have time to develop due partners who can take this forward in the next years as we develop the technology and the standards work, which I agree is very, very important.

But what we do is have a limited amount of time. We have the funding that goes out for a full year. So that gives us a chance, I think, to develop new collaborative relationships with somebody who could take this forward for us. So I want to just, you know, just say PIER does support this work and is looking for a smooth transition to make sure that this important work continues.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Linda.

I have one blue card who indicates, the person indicates she would like to speak to this issue. Nora Sheriff.

MS. SHERIFF: Thank you. Nora Sheriff for CAC and EPUC. I have two very brief, quick points to make. First, my understanding is that there are many existing Rule 21 interconnections at the transmission level. So in terms of whether or not Rule 21 could apply to the transmission level interconnection, it has in the past.

And second, I just wanted to describe one discouraging experience that an existing cogeneration facility has had with PG&E in terms of their Rule 21 interconnection. This facility was looking at doing some upgrades to their equipment, some maintenance work, and they're already interconnected under Rule 21. And at one point PG&E was saying, you have to file a new Rule 21 interconnection application for this maintenance work.

And this isn't a large facility, not even by PG&E's ten megawatt standard, it's a six megawatt facility. And it's just been a very long, discouraging and difficult process and we're trying to work through it but it hasn't been conducive to encouraging existing cogeneration to perform maintenance and efficiency upgrades.

And I just wanted to make that point, thank you.

ASSOCIATE MEMBER BYRON: If I may.

PRESIDING MEMBER PFANNENSTIEL: Thank you for making the point.

ASSOCIATE MEMBER BYRON: If I may. Ms. Sheriff, may I ask you a question about that?

Not necessarily getting into particular cases but do you think Rule 21 would be able to help situations -- if the Rule 21 working group were to continue in some way would it be able to help situations like this?

MS. SHERIFF: Well it might. You know, CAC and EPUC have participated actively in the Rule 21 working group. But when we have tried to address these issues rather than hijack the entire working group meeting to address the issue of a single facility, you know, you try to address the issue off-line. And we have still been faced with reticence on the part of PG&E to work with us. We had to bring it to a relatively high level within the PG&E organization to get some understanding that this should be a very simple matter. And it was a very frustrating experience.

ASSOCIATE MEMBER BYRON: You used the word hijacking the working group. But my sense is that part of what they do is dispute resolutions like this. Don't they, don't they provide some consistency on interpretation of interconnection that would help resolve these kinds of issues?

MS. SHERIFF: They do and that might. I think this might have been a new issue in terms of when you do maintenance to an existing facility. The Rule 21 working group has primarily been involved with new interconnections and this is an existing facility.

ASSOCIATE MEMBER BYRON: Okay, thank you.

MS. SHERIFF: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Anybody else on this specific subject?

MR. HEINZMANN: I'd like to.

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. HEINZMANN: My name is Joe Heinzmann, I'm with FuelCell Energy. In particular on the interconnection items and also with the Rule 21 group.

Part of the Rule 21 process was establishing the certification procedure and then the working group also provides the review of the certification. And we'd want to ensure that if the Rule 21 working group was discontinued that the certification procedure would be continued in some way. We want to make sure that's not dropped off to the side. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Got it, thanks.

Les Guliasi, you're going to --

MR. GULIASI: Thank you, Chairman Pfannenstiel and Commissioners.

I have with me today Fred Skillman who is a member of --

PRESIDING MEMBER PFANNENSTIEL: Les, please identify yourself for the record.

MR. GULIASI: I'm sorry. Les Guliasi with PG&E. I have with me today a colleague, Fred Skillman, who is actually a member of the Rule 21 working group. He is actually familiar with the situation that we just heard about and I would like for the benefit of the record for you to hear from PG&E's perspective an explanation of that situation. And certainly we'd be very happy to take discussion off-line to see if there's any further issue that we need to resolve.

PRESIDING MEMBER PFANNENSTIEL: Well my preference is that we take discussion off-line but I do think since it has been raised perhaps just to mention a response. And then any further discussion I think it does not belong here but we'll --

MR. GULIASI: I agree, but I just wanted this on the record. It will probably take 30 seconds, thank you.

MR. SKILLMAN: Good afternoon, my name is Fred Skillman with PG&E. Just responding to the comments of Ms. Sheriff as it pertains to this particular interconnection, which I'll keep the name of that customer.

PG&E had proposed a process to the customer that would have saved them a considerable amount of money. Being customer focused as we are to all of our customers, and DG customers as well, we had proposed a process that would have saved them thousands of dollars. The customer had some concerns about other agreements that they had with PG&E and chose not to take that particular route.

So because of that and in the process itself at the end of the day we're able to get the issues resolved to the customers benefit. But I just wanted to be able to state that PG&E was very much customer focused in this and we offered an avenue for them that would have saved them a considerable amount to do the same work.

And as Les mentioned, if there is any other details or others, if they'd like to discuss those in detail off-line I'd be happy to address those concerns. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner.

ASSOCIATE MEMBER BYRON: If I may.

Mr. Skillman, notwithstanding the issue that you're discussing can you give me your sense as a member of the Rule 21 working group of its value in continuing in some capacity.

MR. SKILLMAN: I think the primary benefit of the Rule 21 working group is that it is the only form that exists that includes all stakeholders in the community. As Mr. Whitaker's presentation outlined, many different organizations, the people that are involved there, that's I think the primary benefit.

It is a forum and sometimes it can be contentious but that's okay because the issues get out on the table and they get resolved. We've been dealing with for the last several months this issue of funding. And there's essentially in our next meeting, which is right here in this room on the 15th of May, we're going to be discussing an exit strategy as one of the agenda items.

But certainly having a forum that's open, that's under the public auspices of the CEC, is something that all stakeholders actually prefer and PG&E supports that.

ASSOCIATE MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank

you.

Moving on then to the next area of discussion, which is the DG goals and the roadmap. I'll turn it back to John.

MR. SUGAR: If there is no question on the phone then we'll --

MR. DAVIDSON: If it's all right I'd like to make one more comment on the interconnection issue.

PRESIDING MEMBER PFANNENSTIEL: You need to come up to the microphone.

MR. DAVIDSON: My name is Keith Davidson with DE Solutions and I'm going to represent Tecogen. Tecogen is a packager of small combined heat and power systems less than 100 kilowatts in size and simplified interconnection is critical to their business viability in California.

We just want to support the comment made by FuelCell Energy that the certification process needs to continue or perhaps there is some other way like defaulting to the UL certification and that enables the simplified interconnection approach.

I also wanted to just mention a couple of situations for -- this is combined heat and power interconnecting with the grid. You can, you've got a couple of choices. You can, you can opt for the no export interconnection approach in which case not only can you not export any power back into the grid but you have to maintain a ten percent purchase margin from the utility at all times. And the other option is that you can go through -- it requires additional costs for metering -- is what they call inadvertent export, which allows you to push a certain amount of electrons back into the grid for which you are given no value.

And to us this does not, this doesn't seem very rational. There's already been exceptions made for all of the net metering technology. It's not a safety issue. And that we feel that some form of, you know, net metering or compensation of selling excess electricity back to the grid, particularly when the thermal load there is there and justifies the production of additional kilowatts over and above what the, what the facility needs. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

I understand there is somebody on the

phone who wants to speak to this issue. John Bonk-Vasko.

MR. McALLISTER: Yes. Actually this is Andrew McAllister. I am here with John Bonk-Vasko who is our self-gen program manager. We are with the California Center for Sustainable Energy, which is the new name of the San Diego Regional Energy Office. So I just wanted everybody to have that on their radar screens that we have changed our name. So CCSE or something like that will be appearing rather than SDREO in future documents and proceedings, et cetera.

I thought the roadmap was a beautiful report nd we just had one question about the definition of DG. In particular that it excludes non-CHP digester gas and landfill gas. And it just brought up the question for us because, you know, the self-gen program does provide incentives to projects and one of the renewable, one of the renewable fuels that's eligible, those aren't included in the Level 2 incentives for the self-gen program. And particular, for example, municipal wastewater treatment plants that would have digester gas available to do on-site generation that generally is not CHP. So how would that fall under the definition of DG in the sort of newer or updated definition in the roadmap?

PRESIDING MEMBER PFANNENSTIEL: John, would you like to answer?

MR. SUGAR: Well that's an issue for discussion today, probably under DG goals and the roadmap or public comment. We have had a number of people comment in the background that the definition of distributed generation is narrower in the report than many parties would like to see.

PRESIDING MEMBER PFANNENSTIEL: Okay, so we'll move into that area now. And, Nora, were you going to lead this discussion on the DG goals and roadmap?

MS. SHERIFF: Good afternoon. Again my name is Nora Sheriff, I'm here on behalf of CAC and EPUC. And just briefly to add to the names of the member companies of CAC and EPUC, we also have Valero, Era and Occidental.

Now I am going to talk about a 2007 plan for cogeneration. And I'm calling this a 2007 plan to underscore the need for action now. The time for the Energy Commission to act is now.

If the Energy Commission wants to make

its 2020 vision for cogeneration, that is the retention of existing, large cogeneration facilities of 8,155 megawatts, and the encouragement of the development of new, large, cogeneration facilities, that is 3,045 megawatts by 2020, you need to act now. As Commissioner Geesman said in the beginning of the afternoon, you need to bring a strong dose of reality to the rhetoric that is present.

Why do you have to act now? Because you have large industrial sites that are looking at expansion. They are considering these expansions because they have increased thermal needs. If you asked a refinery manager what size cogen would optimally match your thermal need he would say, 500 megawatts. What size cogent facility would meet your electrical needs, between 50 to 70 megawatts might be your answer.

And size matters in terms of the efficiencies that you get, the greenhouse gas emissions reductions that you achieve. You need to be looking at these larger facilities. That's why there's a goal of 3,000 megawatts of new facilities by 2020.

The state needs to encourage sizing to

meet thermal demand. And this is a key point The thermal demand is going to be met with or without the byproduct of electricity. That means that there is an opportunity now to incent new, large cogeneration facilities. But if you don't take away the regulatory uncertainty these facilities are going to meet their increased thermal demand with boilers, or with smaller size cogeneration facilities and boilers.

Now the roadmap addresses three areas of uncertainty that can impact the sizing of cogeneration facilities. Sales of excess power to the interconnected utility, the interface with the California ISO tariffs. And the roadmap also says they want to eliminate departing load charges by 2011. I am going to address the first and the last of these areas.

In terms of excess power sales to the utility the 2005 IEPR was fairly clear in terms of the Energy Commission's intent that all cogeneration, regardless of size, was beneficial and should be in the loading order.

The roadmap, however, provides definitions of DG and large cogeneration and small cogeneration that might lead some to argue that large cogeneration, facilities above 20 megawatts in size, are not in the loading order. And this could lead to continued utility pushback from sales, from purchases of excess power from large cogeneration facilities.

So what can the Energy Commission do now? You can confirm that cogeneration of all sizes should be considered to be in the loading order by clarifying the roadmap and its definitions. And you can also clarify that again in the 2007 IEPR. And then at the Public Utilities Commission addressing the question of need for utility procurement in the ongoing long-term procurement plan proceeding R0602013. The Energy Commission can participate actively in workshops, hearings and briefing on this issue.

And just to give you a point of reference, PG&E has said in their testimony that the cogeneration that is in the loading order is limited to ten megawatts and PG&E has forecasted 28 megawatts a year of new installation of cogeneration.

Now if you contrast that with the 2020 vision of 3,000 megawatts of new cogeneration and large facilities above 20 megawatts you are not going to get there with PG&E's forecast and PG&E's definition.

Southern California Edison limits cogeneration that is in the loading order to facilities less than five megawatts and Edison's forecast for new cogeneration is 25 megawatts a year. So we would like the Energy Commission to actively participate in the long-term procurement plan proceeding to help make the 2020 vision become a reality for large cogeneration.

And finally on the departing load issue. The roadmap calls for the elimination of departing load charges by 2011. However, as currently adopted by the Public Utilities Commission departing load charges could extend into the 2030s and now cover close to 6,300 megawatts of ongoing utility normal course of business procurement.

There is no way to quantify these new departing load charges and the significance of this cannot be understated. This has a phenomenally chilling impact on the development of new cogeneration facilities.

What can the Energy Commission do? You can promote the roadmap goal of eliminating departing load charges by 2011 by participating in track three of the long-term procurement plan at the PUC. That's R0602013. And you can also support EPUC's petition to modify D0412028 and R040403 where we argue that cogeneration should be exempt from the new utility procurement departing load charges. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

Are there questions from the dais of Ms. Sheriff? Dian.

CPUC COMMISSIONER GRUENEICH: Yes. I think you have properly identified that a number of the issues that are in the staff report are teed up for decision by the PUC and especially in the long-term procurement plan. That while I haven't read the filings that you've noted it sounds like that issue of where to put changes in the loading order have been teed up.

So I just want to reiterate what you said, which is for anybody who is interested in any of the issues that are pending before the PUC, please come and please participate because we will e getting decisions out on these matters. And if you do have a particular viewpoint you want to make sure that we know and take into account when we make our decision please come and participate.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Byron.

ASSOCIATE MEMBER BYRON: Ms. Sheriff, good comments. I think I'll hold off on asking some questions after our second presenter but thank you very much for your comments.

MS. SHERIFF: Thank you.

PRESIDING MEMBER PFANNENSTIEL: And the next presenter is Les Guliasi.

MR. GULIASI: Thank you and good afternoon. I'm Les Guliasi with PG&E. I want to thank the Commission for the opportunity to be included in today's program. Particularly to Commissioner Byron for resurrecting this important topic and for John Sugar for presiding today and Gabe Taylor for organizing today's workshop.

ASSOCIATE MEMBER BYRON: Mr. Guliasi.

MR. GULIASI: Yes.

ASSOCIATE MEMBER BYRON: If I just make correct you. I did not resurrect this topic. This is an IEPR topic. It's been on the agenda every time it's on the cycle. I'm just adding my support for it.

PRESIDING MEMBER PFANNENSTIEL: But he

is championing it.

MR. GULIASI: Yes, thank you. And I'm surprised that no one brought up today the most important energy topic that was in today's headlines since we're talking about DG and that is harnessing the jet stream.

(Laughter.)

Well my objective today is implied in the little title that I attached to my presentation. What I am here to do is offer a commentary and a critique of the roadmap and the vision for distributed generation and cogeneration. I want to do this by posing some questions about the assertions and the assumptions embedded in the report with the hope of stimulating some further discussion and a constructive dialogue.

I am not here today necessarily to advocate a particular point of view and I am especially not here today to advocate a utility point of view, although I have to say in full disclosure that contrary -- well first of all that if some things do creep through I'm only human. But I do want to say at the outset that contrary to popular belief utilities in general, I think, and certainly PG&E in particular, is not philosophically opposed to distributed generation, nor are we opposed to cogeneration or what we call combined heat and power.

I agree with the report's assertions that there are institutional and historical barriers to the deployment and development of DG and CHP and it is important to penetrate these assumptions and these assertions and to put all the cards on the table and to target solutions where they're needed.

Utilities, and my utility PG&E in particular, support distributed generation as one service option among many available to customers to address their energy needs. Distributed generation and cogeneration should be components of an environmentally sound energy policy, especially insofar as they promote technological efficiency for society.

So herein lies the first question that I want to pose and it's a question of definition. In previous policy debates about distributed generation and combined heat and power we were very sloppy in our use of terms. We had no clear definition and we mostly talked past one another out of individual self-interest.

So I was happy to see that at the outset this report took a step at making some clear definitions for distributed generation and combined heat and power, with clear operational definitions with respect to size, technology and location. So my question is, are these definitions adequate? Do they need more refinement or can we agree with them and just move on to have constructive conversation.

Now I said a moment ago that the utilities support distributed generation as an option for customers to meet their energy needs. And I would include cogeneration along with distributed generation as a tool for customers.

But utilities in addition to being service providers to end-use or retail customers are also in the procurement business. We buy power in the wholesale market for retail distribution and sales. So from that perspective the picture looks a bit different from the procurement side.

Instead of dealing with retail customers and providing them with a service option to meet their needs, in procurement you're looking for a good deal, usually price, for a product that meets your portfolio needs. And again here you're acting on behalf of retail customers. You're a middle man seeking products at a reasonable price to fit into a portfolio of products and services that you deliver to the retail customer.

So my next question is in reading the report, what is the over-arching policy objective that we're striving for in promoting distributed generation and combined heat and power? I would recommend that a chapter be added to the report to place the DG roadmap in a broader social context and explicate the public policy objectives that we are trying to achieve.

Oftentimes DG and CHP are advocated for energy supply diversity, for energy reliability, to promote efficiency, for technological advancement, for cost or for environmental benefits. So the question is, what are we trying to achieve? It's important that this report provides some broader social context to understand what we're trying to achieve here in promoting distributed generation and combined heat and power.

As the report somewhat implies and

almost states, all electrons are not created equal and it is important that we understand what the origin of these electrons are and place them in a larger social context.

I want to say a couple of words about the process that led to the report, particularly the vision for 2020 and the visioning process.

Exercises like the one used to develop the vision for 2020 are generally self-contained exercises. By that I mean they adhere to an internal logic and often sort of trap themselves in a set of scenarios that they create. And you can see on page 13 the four scenarios that the report identifies.

The scenarios themselves may offer the use of a construct to help us classify in broad distinctions but ultimately we must recognize that these scenarios are depictions or representations of reality, they are not reality itself. the scenarios are internally and logically consistent but they are lacking in practical terms. Reality is made up more or less by a jumble of the elements that we see contained in each of the scenarios but reality isn't so neat. I'm just going to give a couple of examples.

The roadmap talks about the regulatory framework but it doesn't make clear that it's the regulatory framework that governs the investor-owned utilities. What about publicly-owned utilities and a policy framework for the whole state? Is the vision for 2020 adequate or is it limited by its own construction? Should it be expanded or modified to encompass a broader definition of regulatory regime and should it strive to take a broader, statewide perspective.

I think in the interest of time I won't talk much about the issue of incentives and subsidies but just in brief, we have to, again we have to target our solutions where they're needed and not just apply blanket peanut butter-like spreading of solutions across technologies and across industries.

Distributed generation is a market with nascent technologies and here incentives may be important. Combined heat and power is a more mature industry with well understood technologies and proven technologies, often with large and sophisticated players. I would submit that incentives are not necessarily needed in this market.

As Mr. Schoenbeck from CAC and EPUC said a little bit earlier in his remarks, his clients design and sign a cogeneration system which results in a heat rate of about 5,000. Well in a market where the target you have to beat is about 7,000 or 8.000 heat rate these facilities ought to be quite competitive and they ought to do well in the utility solicitation. And with a long-term contract in hand they should have an abundant revenue stream to make a good payback for their investment.

We just heard a moment ago from the other representative from CAC and EPUC and she talked about the vision to achieve a large number of megawatts in a relatively short period of time. Well the question that I have is, if we're going to put these new thousands of megawatts into the system where's the baseload demand to support this huge increase in baseload production?

This Commission is responsible for looking at supply and demand. I think we ought to take into consideration forecast and demand when we talk about forecasts, excuse me, projections and production. I'm just looking over my notes here to see if I can sort of cut some of this down in the interest of time.

The vision for 2020 on page 20 talks about mandatory targets such as a market penetration of 26 percent of total peak load demand being met by DG and large cogen with a mix of technologies and fuels.

Okay, this seems to be a reasonable approach and perhaps it's wise public policy. But we're left with little explanation in the report as to exactly where this number came from and the analysis to support it. It seems to be based in part on a reasonable projection of today's technologies and market penetration. But we don't know much about the vision or what the vision is based on. Nor do we have much explanation in terms of the analysis behind that target.

So the next question I have is similar to the question I posed before about the visioning process. Is the vision adequate or do we need further analysis, or at a minimum, further explanation of the assumptions that led to a conclusion? And a conclusion in a report that could likely lead to a policy recommendation.

So I think there's some more work that needs to be done just to provide some further analysis or explanation about some of the recommendations that we see in the report.

And the final thing I want to raise has to do with the strategy or the pathway to attain the vision as laid out. And here in chapter four of the report you really finally get to the meat of the issue. And as John Sugar outlined in one of his slides, there are three elements of the strategy. They being to support incentives in the near term, to transition to new market mechanisms and to reduce remaining institutional barriers. There is even a very useful time line that I identifies steps that we need to take between now and 2020 to achieve our vision.

So I think the greatest value in this report lies in chapter four but from my perspective that is really only the starting point. In fact we don't really know what the end game is because we can't know the future, by definition.

So my final question is, what do we do next? If we accept that this report and today's workshop is the beginning who will map out the times and places for taking the next steps. Who is in charge? Who will gather the troops? Who will ensure that we get the right stakeholders present? And what are we going to do to ensure that we have a full, statewide policy in place?

Division is a good guide and it could guide our actions and the pathway can serve as a checkpoint along the journey. Now we need to start the engines and head down the course. That concludes my remarks, thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Less. Questions? Commissioner Byron.

ASSOCIATE MEMBER BYRON: Mr. Guliasi, I'm glad to see that you're human.

(Laughter.)

MR. GULIASI: Some things did leak through I guess.

ASSOCIATE MEMBER BYRON: Yes, I think they did.

MR. GULIASI: I couldn't help myself.

ASSOCIATE MEMBER BYRON: But that's okay. You asked a question, what is the objective in promoting DG and CHP in the larger context of things. Can I ask for your view on that?

MR. GULIASI: Well I think I laid out some of them sort of rhetorically when I talked about what we typically hear about the value of

CHP and DG. And certainly I'll just repeat them. I think these are certainly some of the elements, there may be others.

But we talk about increasing the diversity of supply. Certainly there is reliability. We need to have a reliable supply of energy. We need it time-specific and we need it for the long-term. Efficiency. Again, I think a lot of the underpinning here about the value has to do with efficiency. Economic efficiency, social efficiency, technological efficiency. So to the extent that those issues are squarely on the table, fine.

We talk about technological advancement. On the DG side we see all sorts of new technologies emerging and we ought to support those technologies. We have the whole overlay of what to do to reduce greenhouse gas emissions and these new technologies need to be front and center when we begin to address that whole issue of greenhouse gas reductions.

Cost is an important consideration. You know, we have the whole spectrum of issues related to environmental benefits.

There may be other criteria but at least those are the ones that came to mind when I was thinking about the report over the last few days. But we need -- My point was we really need clearly to identify what those benefits are from a public policy perspective and design our actions to achieve those broader objectives.

ASSOCIATE MEMBER BYRON: You know, I'm reminded of comments that I made five years ago before this Commission as well and in some ways they haven't, they haven't changed much. In my mind it comes down to customer choice.

It's interesting to me that where we have customers that are willing to invest money in the generation business and to not receive, not necessarily benefit for it but it's characterized as a negative. I'm not saying this properly. But everything that they are trying to do is a problem for our investor-owned utilities. Where is the thank you in that for them, if you will?

And I'm struck because in recent years, in the last year or so, I have seen a couple of projects in the public, the publicly-owned utility sector. And in fact I think we have maybe one or two POU members here that might be able to speak to this different thinking if you will, Les.

Whereas POU rates on the average are about 40 percent less than investor-owned rates and we wouldn't expect distributed generation to compete very well in those service territories.

But we're finding a completely different response on the part of the publicly-owned utilities working with their members. I'm sorry, with their customers trying to figure out tariffs that work. And I'm just struck by the difference of approach that those utilities are taking versus the investor-owned utilities. So maybe that something to do with your humanity that you referred to earlier. If there is any publicly-owned utilities that are here and would like to speak to that a little bit I'd appreciate that.

But I would just emphasize that I think it really comes down to customer choice and it needs to go a lot further than just speaking positively towards distributed generation and CHP. What do customers want and need and understanding why they need it? Those are the over-arching policy issues that -- that's the over-arching policy issue that I think we're interested in addressing.

MR. GULIASI: I agree with you. I

think, you know, customer choice is an important consideration. And if you recall from the discussions or the debates about the restructuring of the electricity industry, PG&E was one of the few who sided with customers and decided that we should do everything we could to enable customers to make their own choices about their power needs.

So what I said at the outset was that insofar as, yo know, DG in particular was concerned we see that as an important option for customers to help them to manage their energy needs. And even on the CHP side.

I just want to say parenthetically that on something that the report talks about that -- I had it included in my notes but I just skipped over it in the interest of time. Transparency is important here. We have -- You know, the Rule 21 working group has made a great deal of progress and you saw some of the statistics about reducing the amount of time for interconnections and the cost of interconnections. That from our perspective is one important example of putting the customer first.

But the tariffs are complicated, overly complicated. They are written in regulatory jargon, they are not easily understood. I think that they should all be rewritten along the same lines that the SEC asked corporations to rewrite a lot of their shareholder documents so that people could understand them, people could understand them in plain English. So transparency is important. That's just a parenthetical remark.

But in reflecting on your thought about customer choice I think you have to, you know, ask yourself, at what point does a customer stop being for the moment a customer that is receiving a product or a service from a utility and at what point is that customer now a supplier. It's a whole different arrangement, it's a whole different relationship.

ASSOCIATE MEMBER BYRON: Well in fact that raises another question I was going to ask Ms. Sheriff, and I believe Don Schoenbeck got into this as well. For the most part, as I understand it, your customers are not interested in being suppliers. I believe, I believe that you said something to that effect.

MS. SHERIFF: That is correct. We don't, we're not interested in --

PRESIDING MEMBER PFANNENSTIEL: If

you're --

ASSOCIATE MEMBER BYRON: If you'd step up to the podium I'd appreciate it. But let me just ask my question. Has there been any effort to work with the investor-owned utilities in maybe some sort of private/private partnership here? I was going to say private/public but that really doesn't apply.

MR. SCHOENBECK: As far as I'm aware there has not been a private partnership between some of the large CHP facilities in the state and the IOUs with respect to this issue.

But what I was saying in my remarks, they do not want to deal -- our clients, and there is one exception that is a market participant with respect to the ISO and does do the scheduling of an incremental amount of power that is not sold through a bilateral contract. What comes from that is almost a daily administrative burden on that CHP facility to deal with the ISO.

From our perspective for the cogeneration facilities that have been in place for 20 years and delivering their power at their traditional interconnection point they have not had that administrative headache of dealing with the Cal-ISO.

So that is why we have taken the position we have in saying that the utilities are a much larger system so they can accommodate the CHP facilities and deliver them into a coordinated interface with the ISO. So we just see that being a much more cost-effective measure than making every CHP its own scheduling coordinator and having to have an operator desk, you know, 24/7 to deal with the ISO.

So it would be a natural partnership. That's one we need the IOUs to step forward with.

ASSOCIATE MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. We have a number of -- Thanks, Les.

I have a number of blue cards from people who would like to speak to this issue so why don't we work through them. Starting with Gary Schoonyan from Edison.

MR. SCHOONYAN: Thank you. My name is Gary Schoonyan representing Southern California Edison Company. I put a few brief slides here and we did file a number of, a number of comments with regards to some of the concerns that we had and some of the focus that we felt that the roadmap needed to take.

I am not going to go through. I mean, we basically discussed every one of the recommendations and had some comments on that, I'm not going to go through those. Nor am I going to go through some of the things that have already been discussed. I think Mr. Guliasi talked about resource planning, the concerns and the issues of that. The need for -- you know, why do you need incentives if you've got a 5,000 effective heat rate, for one. Those sorts of things.

But I did want to just -- One of the things that I felt and Edison felt was missing in the report is that there wasn't any -- some clear objectives and clear goals with regards to performance of the facilities. There was a lot of discussion and talk about how much benefits these facilities provide to the system. And believe me, some of these facilities provide significant benefits to the system and we aren't going to argue that and we'll demonstrate some of the historical overview of that.

However, we believe a sound CHP policy, and DG policy but particularly CHP policy, is one that reduces overall fuel consumption, reduces overall emissions since they're basically inversely proportional to efficiency. That basically the non-participants, electric rate payers are held harmless.

We are providing significant incentives in many instances for these projects. I've testified before this forum as well as the EAP forum and indicated that given those incentives, given the significant efficiencies associated with these projects if they're designed and operated correctly, there are significant benefits.

Rate payers that paid into this should receive some of those benefits, or at least be held harmless. There should be no degradation of system reliability and there should be the development of clear design and performance requirements for the systems.

One of the other things that at least in going through the roadmap that we saw that failed to exist was sort of an inventory of the incentives that exist today. Now granted not all projects have access to all these incentives. I'm not suggesting that they do. But in essence between the DG and the CHP there are significant incentives already available to them. And we heard today about an additional incentive or benefit, namely the air credits associated with the project.

Our comments, basically that we believe that actual performance -- from what we've seen the actual performance of the near-80 systems, CHP systems on our system, only five percent have shown or have met the 80 percent claimed efficiency that developers and advocates have basically put forth. And since emissions are inversely proportional to the efficiency in many instances existing CHP despite the claims have actually increased emissions compared to the CCGT and the current higher efficiency industrial boilers.

What is needed in the roadmap and going forward is clear design and performance criteria that attempt to match the size and operate the CHP systems to meet the on-site thermal and electrical load. You need to have provisions in place to monitor the performance.

And as discussed before, the export of electrical energy should be incidental. A lot of these projects export a significant amount of power to the grid and apply with all local air quality standards.

And again, the performance and the design for new CHP systems in particular just -- they need. It's a very important part of the system design. And to the extent that the roadmap comes up with design criteria, operational criteria for these we'll get all the benefits that are claimed, as well the state should.

I won't spend much time on this. The vast majority of the projects that exist for potential CHP are topping cycle projects. You produce the electrical energy followed by recovering the waste heat to basically displace other natural gas-fired energy requirements.

And the one thing I want to bring up with this slide is, and I posed it as a final question in my comments that I filed late last week, is since the vast majority of the projects actually benefit through the reduction of natural gas shouldn't natural gas be a key provider of the incentives to get this stuff going forward? Why should it all fall on the shoulders of electric rate payers?

I mentioned the industry. I just quoted several organizations that have talked about the efficiencies. Eighty percent, some in excess of 90 percent total efficiency. The American Council of Energy Efficient Economy talks about CHP systems exceeding 80 percent. The CCA (sic)/EPUC basically uses 80 percent. If you go on the website of the Energy Commission and you look at their example you talk about 85 percent as being the total efficiency associated. And as I've mentioned, that does not come close to meeting what historical performance that Edison has seen.

And Edison has purchased a lot of cogeneration. I mean we've purchased well over ten billion kilowatt hours a year from a number of different projects. And if you take a look at where these projects actually perform at only three out of the close to 60 projects actually even meet or exceed the 80 percent efficiency requirement.

If you take a look at a CCGT with a good industrial boiler nowadays you're probably talking about 80 percent, maybe a little bit below 80. No, pardon me, 70 percent, a little bit below 70 percent, 66 to 70 percent. So that would basically fall right about in here. Anything below that the system can basically provide more efficient use of the fuel than moving forward with something like this.

And these sorts of considerations we could be taking into account. We're looking for reduced natural gas use, we're looking for reduced greenhouse gas emissions. Let's make sure that the criteria that we have going forward to meet those, actually we obtain those benefits.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Gary.

Questions? Discussion?

Interesting information. Yes, we have somebody who'd like to speak to that. Kim.

MS. CROSSMAN: Hi, thank you. Regarding the industry standard of 80 percent efficient. Industry standard says cogeneration ranges between 60 to 85 percent efficient. A blurb that's a leftover on the US CHPA website that refers to over 90 percent efficient systems I could have sworn was removed about a year and a half ago.

There is a tendency sometimes in the industry to overstate benefits when you're trying to promote something. But the system I referred to earlier that won that Energy Star award at

CalTech is a 70 percent efficient system and exceeds the performance of a combined cycle gas turbine and an 80 percent efficient boiler. So very, very few systems will exceed 80 percent. Only the largest really will get there.

And the one other comment I would make is when considering what is beneficial, although I talked about being able to beat a new combined cycle gas turbine and an 80 percent efficient boiler. With some systems I think some consideration probably needs to be given to whether that is in fact the baseline that we're actually trying to beat in California. You know, what is the existing efficiency of the gen. It is in fact all combined cycle, brand new gas turbines or not. Thank you.

PRESIDING MEMBER PFANNENSTIEL: That's a very good point, thank you for raising it.

MR. SCHOENBECK: I'd just like to make one quick comment too on doing energy efficiencies between CHP facilities and utility facilities because you see it all the time in the wars we've been having for years.

I've known Gary for many, many years and I've always really liked him but I think you have to be careful. And you do need to compare an apple to an apple and you need to compare the same technology. And what you see happening you see utilities saying, the state of the art 1,000 megawatt combined cycle plant could give me a heat rate of 6500. And I'll compare that to my existing CHP fleet, which is 1985 vintage and has basically heat rates of 12,000.

So in my mind that comparison can be made but you have to realize what's being done. And similarly you can look at it the other way around. A more new, CHP facility can compare it to the old 9600, 10,000 gas and oil plants that Edison used to own.

I think the most appropriate comparison is have it be the same technology, the same vintage of technology, so by default CHP will always win. You can take a combined cycle plant like La Paloma and have a heat rate of 7,000. If you take that same combined cycle plant and put it in a CHP system it will have a substantially reduced rate. So for the same technology of the same vintage CHP will always win. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

I have some blue cards, others. Ellen Petrill.

MS. PETRILL: Hi. Thank you for the opportunity to comment on the distributed generation roadmap. My colleague, David Timson and Dan Rastler and I wrote these comments and we're pleased to be here to comment.

So EPRI's vision of the future grid comprises diverse assets including large and small scale, both supply and demand. So we agree that distributed generation has a role in the electricity system of the future and there is a need to focus policy on increased DG penetration.

And EPRI commends CEC for looking out to the 2020 time frame for DG penetration and considering what needs to be done today to achieve the goals of the roadmap.

We agree with the three element strategy of the roadmap and we agree with helping the penetration along with incentives is necessary for the near term because the most significant benefits of DG will become more evident and monetizable as the penetration increases. So at some point, and we don't know exactly when, market mechanisms can be developed that in fact pay for the value that diverse, distributed generation will provide.

So we'd like to offer the following additional comments. Number one, win/win outcomes should be the focus of any DG policy that strives to increase DG penetration. EPRI has undertaken several studies of the microeconomics of DG deployment and the costs and benefits that accrue to site owners, rate payers and utility shareholder and society in general. And our studies have shown that there are scenarios under which all three parties benefit from the deployment. We call these win/win scenarios.

Win/win scenarios exist for both customer-owned on-site generation and utility-owned on-site generation. And while there are some cases for win/win outcomes today these opportunities are somewhat difficult to find due to limited monetization of benefits in the market and the cost of DG technologies.

However, as DG penetration increases the macroeconomics of DG will improve due to an increased ability to account for benefits of DG such as reliability. Win/win opportunities will become more prevalent.

So we recommend moving toward win/win outcomes in the future but not to be trapped in today's economic environment. In many cases incentives will be needed in the near term to achieve win/win outcomes until market mechanisms can become sustainable.

Number two, utilities are critical to integrating DG. We recommend that the roadmap give more focus to the role of the electric utility in achieving the roadmap goals. As distribution system managers electric utilities are in the right role to deploy distributed generation to benefit the site owner as well as other rate payers and society.

This will be true for cases where utilities own and operate the on-site generator as well as cases where customers own and operate the generator to power their own loads and/or sell power into the wholesale market.

To expect that utilities will encourage increased DG penetration means that there must be a benefit to rate payers and utility shareholders such as incentives in the near term and monetized benefits through market mechanisms in the longer term. Again, this is the win/win outcome.

Furthermore while we agree that market mechanisms are critical to achieving sustainable DG penetration the mechanism should not focus on competing with central stations and transmission and distribution systems but on complementing these assets.

Number three, pilots should lead the way. We recommend that pilots be used to test mechanisms to increase DG penetration. Achieving the DG and cogen deployment goals of the roadmap is likely to result in major changes in utility planning and in the business relationships between the utility and its customers. So we think that these should be tested on a pilot scale so we can identify the successes and build on those and address the challenges.

So we recommend that in the near term incentive period the focus should be placed on testing and piloting new market mechanisms that result in win/win outcomes. And these market mechanisms will likely require new utility or customer business models and probably regulatory structures as well.

In addition the pilot programs we think should consider advanced technologies such as integrating CHP systems with energy efficiency and PV and electricity storage as we heard about today with a smart grid, for example, and integrating these technologies so you can aggregate the benefits and monetize the values.

We also think that other aspects should be piloted like two-way power flows, intentional islanding and micro-grids.

You may know that EPRI is working with the Energy Commission and the State of Massachusetts through our DER partnership on a DOE States Technology Advancement Collaborative or STAC project to develop and test business and regulatory models that incentivize utilities to encourage DG on their systems.

The pilot projects that we're planning in Massachusetts and California will be a step in this pilot process. We're working with Jose Palomo, Linda Kelly and John Sugar on this project and many other stakeholders in this room and we appreciate their working with us.

Number four. Spark spread is an important driver. We were surprised to find that in figure B1 on page 30 of the roadmap the DG and cogen scenario drivers, it suggested that the spark spread is a relatively low impact factor. Whereas in the studies that EPRI has done we have found that spark spread is the most sensitive factor in the microeconomic analysis. And it's the factor we found that determines whether net operating benefits are available to cover the capital costs. So we recommend that you take another look at the relative impact of spark spread and give it a little bit more visibility.

Number five, consider standby generation for peaking. We noted that there is an absence of standby generation in the roadmap and we know that there are other states that are looking at using standby. Oregon, for example, employs customer-sited standby generators for peaking under various business arrangements. So the installed capacity in California of standby generators are estimated at 10,000 megawatts. This is an enormous untapped resource which could go far to meet the demand increase that is outlined in the roadmap of 14,000 megawatts growth between 2004 and 2020.

Because this capacity is already in place and has been cost-justified for other reasons it is a very low cost electricity capacity for peaking purposes. You would have to do a couple of other things. You'd have to install switch gear and controls to allow the generators to be dispatched during peak periods but this equipment is commercially available and no further development is likely to be required.

And in addition, of course this is very important, you'd have to install combustion controls and exhaust gas treatment to reduce the exhaust emissions to acceptable levels of which is typically diesel engines. And exhaust gas treatment systems are not yet commercially proven but there are technologies under development for vehicles which could be readily applicable to stationary diesel generators.

Nonetheless these costs are likely to be much less than comparable costs for new generating capacity to meet peak loads. So we recommend that the use of customer-sited standby generators be part of the roadmap.

And number six, standardized CHP solutions might be something to consider. Finally, EPRI suggests that penetration of CHP could be improved by developing standardized CHP solutions for key market segments. As with the state's leadership in the specification of energy efficiency for new buildings and new homes, similar specifications and standard sized CHP packages could be specified for new building construction.

So thank you for the opportunity to comment and we look forward to working with the Energy Commission to bring the roadmap to fruition.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ellen.

Are there questions?

Thanks very much for being here. I'm sorry, Dian.

CPUC COMMISSIONER GRUENEICH: I just wanted to say that unfortunately I'm going to have to take off now so I do apologize that I won't be able to stay until the end. But again I want to thank the Energy Commission for offering to have me here today. I've learned a lot.

And I did want to also note, I think he's here, Andy, Andy Schwartz, President Peevy's advisor is also here. And between the two of us and Jay Morse from our staff we'll certainly take back today some of the things that we've heard.

Because I think that there's been some

very valuable input to some of our pending matters. The issue of the continuation of the Rule 22 (sic) working group seems to be an area that we can work on, even in advance of whatever formal documents will come out so that we do have some assurance that this type of collaborative group can continue.

So thank you again for letting me be here and listen.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Dian, thanks for participating.

We have our next speaker, Bob Burt.

MR. BURT: Since this is an IEPR workshop I had come planning to seek your advocacy for an unusual approach to using offsets to deal with global warming. But in view of the lateness of the hour and the fact that I suspect very few people here have a passing interest in that subject I am willing to defer and put my stuff in writing. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions? No?

ASSOCIATE MEMBER BYRON: No.

PRESIDING MEMBER PFANNENSTIEL: Bill Karambelas.

MR. KARAMBELAS: My name is Bill Karambelas, I am the vice president of FuelCell Energy. The comment was going to be on action item number two under tariffs and was already covered by Eric Wong. It had to do with natural gas and the ability to move that possibly into the rate base. Excuse me. So I will step down because it's already been covered. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir. On the phone I believe we have Jane Turnbull from the League of Women Voters. Jane.

ASSOCIATE MEMBER BYRON: She's in person.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, I thought you were --

MS. TURNBULL: I'm behind the podium. Thanks Commissioners, I am pleased to be here.

I would like to first of all endorse what Les Guliasi had to say in terms of asking that a preface statement be laid out in terms of the policy objectives that are being sought.

The League has been a supporter of DG and CHP for as long as I can remember, largely because we support the more efficient use of our natural resources and also the potential for mitigating pollutants.

Commissioner Grueneich did raise the issue of how is this going to fit into a cap and trade system and I think it's a great question and I trust it will fit in but getting there is going to be an interesting process.

We also feel that the potential improvements to the whole reliability of the electric system that can come out of this are very significant and certainly ought to be included.

But Commissioner Byron, you raised the issue of customer choice. And I have to address that because that was a question that we asked League members all around the state a little over a year ago in terms of, was that a value that should be sought in terms of energy policy and we got a resounding no on the grounds that the customers who want to choose are the ones that are going to benefit. And there really continues to be a concern out there in terms of what the impact of policy decisions are going to be on the core customers. So I do raise that.

I also think there is an issue of fairness in terms of departing load costs. We have a lot of load serving entities out there, not just the IOUs, and I think there is a basic, level playing field that is attempted to be established in the tariff development process and hopefully that level playing field will still be a goal out there.

We also like the ideal of a more transparent tariff process. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Jane, let me just ask. Does the League normally get involved in rate design issues? For example, the issues that were raised earlier about demand charges and specific rates.

MS. TURNBULL: We usually don't get involved in evidentiary hearings at the PUC. We are in a position to talk in terms of policy on the broader issue. We don't have the depth to work in terms of the individual rate cases.

PRESIDING MEMBER PFANNENSTIEL: The policy issues on rate design, have you taken those on? Are you talking about cost allocations and cost responsibility? Is there a position?

MS. TURNBULL: That is an area that we are concerned about and we are certainly very interested in the dynamic rate structures that are coming up. We think they are very exciting but they have to be done the right way.

PRESIDING MEMBER PFANNENSTIEL: That's the challenge, thank you. Other questions?

Thank you, Jan.

And we have Alex Kim from SDG&E and SoCal Gas Company.

MR. KIM: Thank you. I'm Alex Kim from San Diego Gas and Electric. I'm here representing both San Diego Gas and Electric and SoCal Gas. I'll make my comments brief because I know we're running late. And we will be filing our comments as well so they'll be publicly available.

But I did want to say that first of all we do commend the Commission for implementing and creating this DG policy roadmap, we do believe it's needed, and that SDG&E and SoCal Gas strongly support cost-effective distributed generation. We also believe that continuing to provide incentives in the midterm, replacing those with market mechanisms in the long term is a very good strategy.

There are a couple of things, omissions, that we feel are on the roadmap and one of them is that cost-effectiveness is not addressed in the division statement. Nowhere is cost-effectiveness mentioned. Also the regional circumstances are not addressed. What are they, how are the different regional areas affected. And lastly the procurement obligations. Increasing net metering is inconsistent with moving forward towards the new market mechanisms.

A couple of recommendations that I just want to address here. Like I said, we'll be filing our comments later. But one o them is -- and this was addressed, a question I guess that was raised by PG&E. And one thing that we feel is needed is to develop a comprehensive and detailed plan that addresses these issues that are not addressed in the roadmap. And that all stakeholders should be considered and participating when developing these strategies.

I think what was discussed initially about the interconnection group. A forum like that where you have all stakeholders involved is a great forum in which this roadmap can also be worked out.

And again, reinstating CHP and the SGIP. We do believe that is a good, that is needed right now, as was mentioned earlier by somebody. The payback that customers are looking for are two to three years. And one of the reasons why CHP has not grown probably as significantly in our area is the fact that our customers are requiring a much quicker payback and maybe in the short term reinstating the incentives in SGIP is needed.

And lastly that other factors including impacting customer decisions to adopt DG such as better site selection, performance requirements, many of the factors that were addressed today regarding customer decisions. Why does a customer make a decision to include distributed generation or to purchase distributed generation is not also addressed in the roadmap and we would strongly recommend that it does be addressed. Thank you.

ASSOCIATE MEMBER BYRON: Mr. Kim?

MR. KIM: Yes.

ASSOCIATE MEMBER BYRON: I want to make sure I understood something you said. Did you say expanding net metering is inconsistent with market mechanisms. Is that what I understood you --

MR. KIM: Correct. With new market mechanisms, correct.

ASSOCIATE MEMBER BYRON: I hadn't considered that. Could you explain what you mean by that, please.

MR. KIM: Sure. I think, I think what the intent, at least our understanding of what the intent of the roadmap was, was to move away toward incentives -- away from incentives I should say. And net energy metering is an incentive. And so we believe that moving away from that or continuing that as described in the roadmap is not really moving towards new market mechanisms.

ASSOCIATE MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. KIM: Thank you.

PRESIDING MEMBER PFANNENSTIEL: That completes the blue cards I have. Is there anybody on the phone who would like to make comments?

Then let me turn it back to John.

MR. SUGAR: For just a moment, please. I'd like to note that I erred on the workshop notice and gave a very short period for comments and wondered if the Committee would be willing to entertain extending the comment period for the next week or two so that parties an docket material as a result of our discussions today.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, until when?

MR. SUGAR: Two weeks from now. That would be about the 21st.

PRESIDING MEMBER PFANNENSTIEL: And what's the IEPR Committee --

ASSOCIATE MEMBER BYRON: Yes, we welcome the comments of individuals that are here and I think expanding it, if we can afford the additional time, would be really worthwhile.

MR. SUGAR: Great.

ASSOCIATE MEMBER BYRON: Notwithstanding all the great comments we've received already.

MR. SUGAR: Yes, and we will be posting those, thank you.

PRESIDING MEMBER PFANNENSTIEL: Are there final concluding comments, Commissioner Byron?

ASSOCIATE MEMBER BYRON: I think I'll pass.

PRESIDING MEMBER PFANNENSTIEL: I have no other than to say that today was a very meaty afternoon. It was a lot of interesting, but I think more than that, informative and very useful information presented.

I think some of the disagreements were valuable for us because they help us on the policy decision-making that we need to do. It's not quite as straightforward as each of the individual sides would have us believe. But I do think, even having said that, there's a great deal of convergence of opinion on DG and cogeneration.

I think that the areas where there are policy disagreements are important ones but not that many of them. And I think that this is a good way of getting started to resolve them.

With that, nothing further, we'll be adjourned.

(Whereupon, at 4:25 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission 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 16th day of May, 2007.