BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of,)
)Docket 11-IEP-1G
IEPR Committee Workshop on)
Distributed Generation)

IEPR Committee Workshop

Distributed Generation – Getting to 12,000 MW by 2020

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MAY 9, 2011

9:35 A.M.

Reported by:
Kent Odell

Commissioners Present

Robert Weisenmiller PhD, Chair and Presiding Member, IEPR Committee
Karen Douglas, Associate Member, IEPR Committee
Carla J. Peterman, Presiding Member of Renewables Committee

Staff Present:

Paul Feist, Advisor to Karen Douglas
Jim Bartridge, Advisor to Carla Peterman
Kevin Barker, Advisor to Robert Weisenmiller
Suzanne Korosec, IEPR Lead
Heather Raitt, California Energy Commission
Linda Spiegel, California Energy Commission

Also Present (*on phone)

Panelists

Panel 1:

Heather Raitt, California Energy Commission
Michael Picker, Office of the Governor
Aaron Johnson, Pacific Gas and Electric Company
Gary Schoonyan, Southern California Energy
Jim Avery, San Diego Gas and Electric Company
Jim Shetler, Sacramento Municipality Utility District
Jeanne Clinton, California Public Utilities Commission
Noah Long, Natural Resources Defense Council
Nicole Capretz, Environmental Health
Bill Gallegos, Communities for a Better Environment
Heather Sanders, California Independent System Operator
Mary Leslie, Los Angeles Business Council
Bill Powers, Powers Engineering

Discussion 1:

Christian Hewicker, KEMA

Panel 2:

Heather Raitt, California Energy Commission
Jon Carruthers, Pacific Gas and Electric Company
Robert Woods, Southern California Edison
Bill Torre, San Diego Gas and Electric Company
Dave Brown, Sacramento Municipal Utility District
Carl Lenox, SunPower
David Korinek, KEMA

Discussion 2:

Heather Raitt, California Energy Commission
Karin Corfee, KEMA
Julia Donoho, Sonoma County

Panel 3:

Linda Spiegel, California Energy Commission
Jan Kleissl, University of California San Diego
Roland Winston, University of California Merced
James I. Zoellick, Schatz Energy Research Center
Peter Evans, New Power Technologies

Also present:

Tim Tutt, Sacramento Municipal Utility District
Ed Murray, Aztec Solar
Bernadette Del Chiaro, Environment California
*Al Baez, Air Quality Management District
Andrew McAlister, Center for Energy Efficiency and Renewable Technologies
Danielle Osborne-Mills, Center for Energy Efficiency and Renewable Technologies
Ray Pingle, Sierra Club of California

I N D E X

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I N D E X

P R O C E E D I N G S

MAY 9, 2011 9:35 a.m.

CHAIRMAN WEISENMILLER: Good morning. Ready to start?

MS. KOROSEC: Good morning. I'm Suzanne Korosec, and I manage the Energy Commission's Integrated Energy Policy Report unit. Welcome to today's workshop on Reaching 12,000 Megawatts of Distributed Generation by 2020. This workshop is being conducted by the Energy Commission's Integrated Energy Policy Report Committee.

Today's discussions are integral to preparation of the 2011 Integrated Energy Policy Report since one of the Energy Commission's top priorities this year is developing a renewable strategic plan that discusses challenges to meeting Governor Brown's renewable energy goals, including the 12,000 Megawatts DG goal, and provides suggested strategies to overcome those challenges

First, some housekeeping items, for those of you who may not have been here before, restrooms are in the atrium, out the double doors and to your left near the glass doors. Please be aware that the exit doors on the south side of the building are for employees only, and you will trigger an alarm if you attempt to go out that way.

We have a snack shop on the second floor at the top of the atrium stairs under the white awning for coffee and such. And if there’s an emergency and we need to evacuate the building, please follow the staff outside to Roosevelt Park which is diagonal to the building, and wait there until we’re told it’s safe to return.

Today’s workshop is being broadcast through our WebEx conferencing system, and parties need to be aware that it is being recorded. We’ll make an audio recording available on our website a few days after the workshop, and a written transcript will be posted on our website in about two weeks.

Our agenda today will cover four topics related to achieving the Governor’s DG goals. We’ll begin with a discussion on developing interim and regional targets. Having interim targets will not only break the 12,000 megawatts into more manageable chunks but will also allow us to better track progress over time towards the 2020 goal.

Next, because one of the major challenges of the 12,000 megawatt goal will be integrating that amount of renewables into our system, we’ll hear from KEMA about Europe’s experience integrating large amounts of DG. We’ll then have a brief public comment period just before lunch, this is mainly for people who have time constraints and aren't able to stay until the end of the day. And we'll break for lunch at approximately 12:30. We'll continue the integration topic after lunch with a panel discussion of what lessons California can learn from the European experience and then next we'll talk about the Energy Commission Staff's report on developing renewable on state buildings and other state owned properties. As the Staff Report notes, deploying renewable DG and other renewables on public buildings and lands will not only contribute towards the governor's renewable goals but it will also reduce energy costs of state buildings, create new sources of energy for the state by leasing vacant or unused lands and right of way, and will provide cost savings to the state through reduced land maintenance costs that would be assumed by the renewable developers who use those lands.

Finally, we'll talk about how research development and demonstration efforts can help advance DG deployment through things like improved forecasting, advanced technologies and a better understanding of where the optimum places are on the distribution grid for these technologies. I will finish up with another opportunity for public comment on any of the day's topics. During both public comment periods, we'll take comments first from those of you in the room, followed by those participating via WebEx. For our in-person guests, we ask that you fill out a blue comment card. These are available on the table out in the foyer so that we may better manage our comments. Please provide your name, your affiliation and the topic on which you'd like to speak and if you need to speak in the morning because of a time constraint or if you can wait until the afternoon. You can give those cards to me at any time during the day. When it's time for you to speak, please use the microphone at the podium near the Court Reporter so we can make sure our WebEx folks can hear you. And it's also helpful if you can give the Court Reporter a business card so we can make sure your name and affiliation are correct in the transcript. For WebEx participants, you can either use the chat or the raised hand function to let our coordinator know that you have a question or comment and also whether you have a time constraint and we'll open your line at the appropriate time. For those of you online that are participating only by phone, we will open the lines at the end of the afternoon public comment period to give you an opportunity to ask questions. We're accepting written questions on today's topic until close of business May 23rd. And the notice for today's workshop, which is on the table out in the foyer and also available at our website, describes procure to submitting comments to the IEPR docket. And with that, I'll turn it over to Chairman Weisenmiller for opening remarks.

CHAIRMAN WEISENMILLER: I'd like to thank everyone for coming today and their participation. I'm hoping that the extent of those of you on the WebEx or other audio connections have good opportunity to follow us today. Obviously this is an important topic. We're hoping to cover a lot of ground today and get a lot of meaningful exchanges and good information. So again, I'd like to thank everyone for their participation and, again, encourage all the speakers to stay crisp so we have enough time for a good back and forth.

COMMISSIONER PETERMAN: Good morning, everyone. Glad to see you here as well. I see a lot of familiar faces. Looks like an all-star cast and so I think we're going to have some very good discussion. Reaching this 12,000 megawatt goal is very important to the state in terms of reaching our climate change goals, our health goals, and our interest in energy security. I think the questions that we are posing today are the right ones and I look forward to this discussion stimulating the talk we're going to have for the next few months and the next few years. And with that, I'll turn it back over to Chair Weisenmiller.

CHAIRMAN WEISENMILLER: Great. Suzanne, you want to kick off the first panel?

MS. RAITT: Good morning. I'm Heather Raitt. I'm with the California Energy Commission. I'll be moderating this first panel. Okay. Good morning.

So our first panel is focused on setting regional and interim targets towards building up to 12,000 megawatts of localized resources that are renewable. And so to kickoff the discussion, staff has created a preliminary for establishing regional targets and this is really a work in progress and we look forward to comments on our proposal.

In this approach, staffs using a bottoms up analysis, building off existing programs and planned projects to develop county specific estimates for meeting 12,000 megawatts. We're thinking about this in terms of renewable distributed generations, so projects smaller than 20 megawatts. It's a simplified approach looking at market and program activity to date and scaling that past-trans to meet 12,000 megawatts. We were interested in doing an overlay of additional considerations such as where DG could be most

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beneficial, looking at an economic analysis and including environmental screens but we may do so in the future. And we welcome your comments on how to do that.

So basically the initial cut we did was we split the analysis into two categories – the first at DG behind the meter to serve onsite load and separately DG they could produce energy for wholesale. So we have—we we are assuming 5,000 megawatts behind the meter and 7,000 megawatts that could be wholesale.

For estimating behind the meter, staff assumed the state would meet its SB1 goals which is 3,000 megawatts. And then to get there, we assumed current trends would continue. And then we added another 2,000 megawatts that we assume would be installed in the more densely populated counties assuming there'd be the greatest opportunities there. For the wholesale portion, we looked at existing contracts, projects going through the environmental review process on a local level and projects that are in the queue for inter-connection. And this slide shows there's about 1,000 megawatts under contract, about 2,500 megawatts going through environmental review on the local level at this point and then we have another 5,700 megawatts in the queue. And we recognize that these aren't discrete buckets, if you will, that there's going to overlap between them. But we also did our best to try to weed that out.

For behind the meter, we scaled up the installation trends to estimate the 3,000 megawatts SB target. We looked at the number of megawatts that had been built per county and simply assumed the same trends would continue going forward for the California Solar Initiative and the low-income programs until their goals were met.

For the new Solar Homes Partnership, that has a goal for 400 megawatts for installations on new housing and clearly that program has been stalled with the housing market, but we did assume that the goal would be met and we based the build out on 2009 building permit data.

For the 700 megawatt public utilities goal portion, we assumed that they would meet their targets.

Looking at behind the meter, we also needed an additional 2,000 megawatts after the SB1 goals would be met. So we again began with looking—excuse me, the existing programs and build out from there. Excuse the acronyms on the slide but we looked at the California Public Utilities Commission’s Self-Generation Incentive Program and the Energy Commission’s Emerging Renewables Program and simply assumed what’s already been installed there would double. And then for the remainder, we assumed that the installations would occur in the top 12 most densely populated counties. So that’s what we did to get to 5,000 megawatts of behind the meter.

For the wholesale distributed generation to get to the 7,000 megawatts, we first looked at the projects that are currently going through local permitting process, which the Energy Commission is tracking, and we also looked at projects that are under contract. We cross-referenced these data sources to try to avoid double counting and the analysis yielded about 3,200 megawatts that we could identify by county. For the remaining roughly 3,800 megawatts, we looked at the inter-connection queue for the projects that didn’t have a contract and weren’t going through the local permitting process.

Then we put all of this data together and we’re showing it here on maps. And this is actually for how, using this methodology, that distribution for behind the meter. And, in this map, the red county shows—the red shows where we expect the most behind the meter installations, followed by orange and then yellow. So the red counties here are basically LA and Orange Counties.

This one shows for wholesale generation the highest concentrations here are San Bernardino, Kerns and LA. So we're seeing a little bit more in Southern California and Central California.

And then here, it's a little bit hard to decipher, but we basically put the onsite and wholesale together. We purposefully haven't shown numerical targets here because the idea of what we wanted to do was to focus the discussion on the methodology and how to think about developing targets for the 12,000 megawatts.

So with that we welcome your input and your comments and we'll move on to the next speaker and—

CHAIRMAN WEISENMILLER: Heather, just one clarifying questions.

MS. RAITT: Yeah, sure.

CHAIRMAN WEISENMILLER: In terms of your analysis, how did you define the projects? What's the maximum size?

MS. RAITT: 20 megawatts.

CHAIRMAN WEISENMILLER: Okay, thanks.

MS. RAITT: Thank you. Michael Picker, I think you can either sit there or come up here.

MR. PICKER: I think this will be fairly brisk. Next slide. This is just a quick over—this slide is just a quick overview of the Governor's—you can’t hear?

CHAIRMAN WEISENMILLER: And also Michael, for folks on the phone could you please introduce yourself?

MR. PICKER: Identify myself? Sure. (Checks microphone clarity with audience and WebEx attendees). This is Michael Picker. I’m the Senior Advisor to the Governor for Renewable Energy Facilities. And this first slide is just a quick overview of new goals from the new Governor for renewable energy during his term. And the first that we list here, of course, is building 12,000 megawatts of localized energy generation, generally projects that are attached to the local distribution grid rather than bulk transmission grid. I’ll let you quickly scan the other goals, I’m not going to focus on them today. Next slide, please.

Again, I’m still learning a lot about this field of policy. One of the things I observed after really starting to focus more directly on distributed generation local energy resources, is that it’s really a different fundamental market in this state. The large cell projects compete to sell power all across the state through contracts. They’re generally in remote locations. It’s somewhat competitive. These local energy resources are going to be positioned in specific parts of the state and, for the most part, they’re not going to be selling energy across the transmission grid to other parts of the state. Which means that they're fixed in place. They're highly shaped by the surroundings that they're located in as well as local markets. And I just wanted to go through some of the issues. Next slide, please.

And again, solar installation is different in different parts of the state. It's much more intense in San Diego than it's going to be in Arcadia. Even the large scale markets, people tell me that there's a discount for solar in the Central Valley over the desert that results in higher costs and less affordability and less likelihood of the utility of a project in terms of meeting financial goals and still contribute to meeting the state's RPS goal. The distribution lines and transformers are going to be much newer in a residential community like Elk Grove than they're going to be in downtown LA which is a much, much older community where some of these transformers have been in continuous use for 40, 50, 60 years. Therefore, their reliability and their ability to handle a variable resource is going to be somewhat more limited. The planning landscape is really different in Ontario and Fontana with the heavy concentration of the goods movement industry than it's going to be in downtown San Francisco which is dense high-rise. So per person, the surface area that you could actually expose to (indiscernible) renewables is going to be dramatically different. And, of course, there’s many more policy arenas in Northern California but there’s much more demand in the south as Heather’s last slide—almost all of the organized groups tend to be centered in San Francisco and Sacramento yet there’s many economic development groups and economic justice groups who are active in parts of the state where the bulk of the folks live. So these are just some of the issues. I’ll give you a couple of others. Talking to the folks who are starting to emerge in the field of community wind, they tell me that local assessors treat the property tax value of the turbines much more differently—dramatically differently. For example, in Solano, which has fairly good wind and is actually the site of a one megawatt wind project that is behind the customer meter and selling into the market through net energy metering. The assessor will continue to assess the value of that based on the constant depreciation whereas in San Bernardino County the assessor immediately discounts the value of the turbine 50 percent the moment it starts to run because that’s its value into resale market. Those things actually have dramatic impacts as do all these others in terms of the costs to the generator in terms of supplying electricity in cost to consumers. So I think that all of these things, again, are going to have impact in the way that people deal with these issues.

Good example that's recently cropped up is in Los Angeles where the LA Fire Department has been very, very active in terms of trying to help develop standards for construction on rooftop has begun to address standards for ground mount. And LA is very hilly. It has a high portion of its land area in chaparral brush and its very fire prone. So there's large parts of the city while on some levels may look good for installation new ground mount but in reality represent a fire hazard and the fire hazard has yet to wrestle with what that means and to set standards and guidelines. I will say that LA Fire Department and State Fire Marshall really helped to structure the underlying tactics that are currently being addressed as part of the International Fire Code for rooftop. So I Have some confidence that they're not just raising issues for the sake of raising issues. I think that they're really concerned and working hard to come up with solutions. But in the midst of all that, we're trying to see the deployment of 12,000 megawatts of renewable energy whether it's community wind, bio-fuels, landfill gas or solar. We're going to have to figure out some way to make this real. I started just by trying to figure out what are the markets in California. Next slide, please.

And I just came up with a rough way for me to begin to characterize this and since I haven't really had a chance to evaluate Heather's model, I'll defer on how quickly I move to the direction that she's setting. Here's where I started. I just broke it down to economic development communities and started to use what date it was available to start to make some rough assessment as to what seemed achievable. There's—this is heavily weighted towards solar which is probably unfair in some markets, but that was the best information that I was able to find at the time. It has no time access. I was uncomfortable using the existing programs for financing distributed renewables knowing there's a lot of discussion in the legislature about whether to reauthorize SGIP or CSI not knowing what that level of the policy terrain was I just kind of went through and developed some public policy categories for financing and then just started to split it up. I think whatever we eventually all can come to terms with as being a reasonable way to divide up the state and begin to pursue these goals, the underlying reality that I'm confronting is that we aren't yet at a single market.

And I think that we may never get to one unified approach that's perfect in every part of the state. However, what I'm starting to see is that there's a lot of issues that we need to begin to wrestle with to create a more efficient market across the state. And I will work with many of the stakeholders here and elsewhere to begin developing some tools through a working conference for later this early summer to try to structure discussions and develop solutions. Thanks.

CHAIRMAN WEISENMILLER: Thanks, Michael.

MS. RAITT: Thanks. The next speaker is from PG&E.

MR. JOHNSON: Good morning. My name is Aaron Johnson and I am the Director of Renewable Energy and Policy at PG&E. I wanted to start this morning by just talking a little bit about some of the DG programs that PG&E already has underway.

First of all we have the CSI program where PG&E has installed more than 300 megawatts of customer-side solar installed. We have an existing feed-in tariff program where we've had nearly 40 projects subscribe. And that applies across technologies. We have seen a number of distributed generation size projects sign up with the utility through our existing RPS RFOs.

We have over 10 projects representing 140 megawatts almost entirely solar, solar PV. A couple of those projects are online and a number of the rest of them will come online later this year and early next. We’ve also initiated—and I did want to add for our RPS RFO, we will be issuing another solicitation in two days time, again, soliciting offers for the full range of utility scale projects as well as distributive scale projects.

The other program—there are two other programs we have underway. One of which is our PV program where we are developing 500 megawatts of solar. Half of it being developed by the utility and the other half through competitive solicitations. We just completed the first competitive solicitation. We got an incredibility robust response and our own projects will be online this fall. Three of the first projects totally 50 megawatts.

And then, finally, we have pending before the PUC, the RAM program for over 400 megawatts. Again, of 0-20 megawatts sized projects. And once that’s approved by the Commission, we’ll be having solicitations as early as this fall to begin taking on additional distributed generation programs.

I highlight these programs because I think it’s worth noting that there’s been a tremendous amount of progress and there are a tremendous amount of programs in place already to begin adding significant quantities of distributed generation to the system.

As we approach the 12,000 megawatt goal we are sort of looking at this and seeking to understand what’s desired and how this fits with existing programs, how does this fit with the existing 33 percent mandate that was just codified earlier this year. How does it fit with the existing programs I just outlined, the CSI, the existing feed-in tariff, our PV programs, the RAM, the RPS program generally.

And basically the way that we think about meeting clean energy goals is ultimately what is it going to cost for our customers to do these programs. And as we meet clean energy goals is one of the things that we’ve observed through our RPS and procurement activities is that generally the smaller projects have been more expensive than the utility scaled programs which is why we’ve done the vast majority of our renewables procurement through larger utility scale projects. To date, there’s a fairly significant gap in price there. I will say that based on some of the most recent information that we’ve gotten out of our latest PV program, we see that gap starting to close a little, which is encouraging, but we're not sure that we're there yet.

So ultimately, the concern that we have about the program is what will ultimately be the rate impact of tackling more clean energy through a distributed approach rather than through a traditional utility scale approach. And we think that's an important lens to look at these programs through. So ultimately some of our questions will center around how much does it cost, what is the technical feasibility; and I know we're going to have a second panel here where we're going to get into some of the technical details and a colleague of mine, Jon Carruthers will comment on some of PG&E's experiences with the technical elements of implementing DG you know like how much of this program would we like to see the IOUs contribute versus the publicly owned utilities versus energy service providers, community choice aggregators. And then, finally, if we're going to move towards this goal, how can we leverage the existing programs that we have. We've made a tremendous amount of progress to have a whole lot of different avenues for procurement and I was very encouraged to hear Michael Picker talk about some of the barriers that may exist to get distributed generation online because one of the challenges we've seen as we've tried to adopt

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a lot more clean energy is that there's been a lot of focus on what the procurement mechanisms are for the programs and not as much focus on what are the barriers to actually bringing the projects online. We can create lots of different new procurement mechanisms; utilities have demonstrated that we've very good at signing contracts for new facilities, however, those new facilities haven't necessarily come online in the timelines we've looked for. So I think those are important things to consider and we look forward to hearing more about how to tackle this goal. Thank you.

CHAIRMAN WEISENMILLER: Thanks. Aaron, a couple of questions. You had mentioned on PV program, the recent one, that you had a vigorous response. What was the ration between bids and what was ultimately signed?

MR. JOHNSON: We received 20 times as many bids as what was actually signed-up. I will caveat that to say one of our experiences with that RFO was that we received a large number of bids from developers who did not demonstrate a lot of sophistication with the development process. There was some basic screens that we put in places for projects to pass through in order to be considered viable. Two-thirds of the projects were unable to pass those screens. I just want to caveat those response with not all of those were necessarily viable bids.

CHAIRMAN WEISENMILLER: Okay. And typically on your RPS solicitation for utility scale, what's the type of ratio you see?

MR. JOHNSON: Certainly what we've seen over time is that it's increasing significantly. We haven't had a general RPS RFO since '09, so it's been about two years; I'm trying to remember back to that RFO, I don't have a good sense of what that number was. It was quite robust in '09 and our expectation in 2011 based on the number of folks that have been approaching us bilaterally is that we will get an extremely robust response.

CHAIRMAN WEISENMILLER: Okay. And the other question was DRA, the PUC's Division of Ratepayer Advocates, did a recent report looking at renewable price trends and bemoaned that the distributed gen numbers were coming down much faster than the utility scale. I don't know if you've had a chance to review that report or want to comment on it.

MR. JOHNSON: I do think that we have seen that trend in projects coming to us. I would say that that gap, while the trend does exist, the gap still exists as well in that the utility scale projects are still less expensive. Certainly that trend exists and I wouldn't refute that trend that is what we see.

CHAIRMAN WEISENMILLER: Okay, thanks.

MS. RAITT: Thank you, Aaron. Our next speaker is Gary Schoonyan from Southern California Edison.

MR. SCHOONYAN: Yes, thank. My name is Gary Schoonyan. I'm Director of Regulatory Affairs of the Southern California Edison Company and we appreciate the opportunity to participate. I also want to thank you for these really nice name tags. It's a very nice touch.

Anyway, although the goal of the 12,000 megawatts of localized energy resources is very laudable, in order to move towards it there are many issues that have to be addressed in a thoughtful, equitable, factual and reasonable manner. Aaron highlighted some of existing programs, I'm not going to go through those, basically what I'm going to do is address some of the issues and considerations that Edison has and is suggesting.

Key among these is the impact on customers, the feasibility of the goal and the impacts of local reliability and infrastructure needs. To begin with, we need to eliminate the myth that pursuing the goal will not require significant system upgrades both in terms of the wire systems themselves but also of the data collection and control systems necessary to reliably integrate large quantities of various types, brands and configurations of localized energy resources.

To begin with, I'd like to make a couple of observations regarding timing and makeup. Regarding the makeup, you may notice that I used the term localized energy resources to define the energy production systems covered. To me, including all clean energy resources seems to make the most sense. This could include systems such as very efficient CHP and energy storage. There should also be consideration for the many localized generation programs that already exist that Aaron alluded to.

Regarding the timing, to me there is nothing magic about getting to the goal by 2020. Granted, you have to show sustainable progress towards the goal. But you must do so in a manner that thoughtfully considers the liability and rate impacts. Having an orderly progression only allows the state to not only bounce progress with non participant rate impacts but also allows the state to take advantage of technological advancements as they occur over time rather than having a mad dash to a goal using today's technologies. Anyone who lived through the ISO 4 gold rush and the dormant subsequent years should appreciate this. In my mind, there is a need for sustainable progress but the 2020 shouldn't just be the date that we subscribe to that.

Regarding the electrical system, I would like to offer a couple of observations. The first is to reiterate what I had mentioned earlier. While there is to be some distribution circuits that can handle large amounts of localized energy resources now, in most instances, there is to be a need for some upgrades. Further, the need for data collection facilities.

Finally, as more and more energy systems are added to the distribution system, there will likely be the need for sophisticated control systems to manage the distribution system. This will not only include the systems themselves, but potentially the necessary controls and standards on the localized generators to accept and respond to various signals.

The level of concern over rates is directly proportional to the amount of subsidies to participating customers and developers will receive. If the energy produced is valued at market rates, there wouldn't be a concern. However, there will likely be a push to provide these projects with substantial incentives and/or power purchase prices. Unfortunately, the non-participants will be forced to pick up these costs.

In closing, I would like to make one final observation. It appears that this effort entails yet another standalone program. The energy industry is currently charged with reliably meeting customer needs with significant demand side resources, 33 percent renewables, the CSI SGIP programs, efficiency HP, energy storage, the RAM and several more I'm sure I've missed. It is hoped at some point the state considers the entirety of these programs together in the context of the impact on the electrical systems and the customer it serves. Thank you.

CHAIRMAN WEISENMILLER: Thanks Gary. A couple of questions. Edison had one of the first utility PV programs. What issues have you ran into implementing that. I think everyone has a vision of trying to line the warehouses going into Ontario Airport and trying to understand what you've found when you were trying to do that.

MR. SCHOONYAN: Are you referring to the Big Box Solar on the industrial facilities?

CHAIRMAN WEISENMILLER: Exactly.

MR. SCHOONYAN: A lot of the problems that we encountered had to do with just—actually it went fairly smoothly. Believe it or not, there were inter-connection concerns. Utility projects, just like customer projects, face connecting to the grid and there were concerns along those lines. The biggest thing that we found, and you're probably aware that we petitioned the Commission to scale back that particular program, is that we found the competitively solicitations were substantially lower cost than what we were able to do on that particular program and enhance in the process of requesting the Commission to scale that back.

CHAIRMAN WEISENMILLER: Yeah, I think you found much better economics in the ground-mounted opposed to the roof-mounted?

MR. SCHOONYAN: Correct.

CHAIRMAN WEISENMILLER: And what drove that? Do you know?

MR. SCHOONYAN: I do not know at this time.

CHAIRMAN WEISENMILLER: In terms of—the other question is in terms of distribution issues, do they tend to be highest in your legacy or in your newest distribution circuits?

MR. SCHOONYAN: More in the legacy but they all have some concerns associated with them, for the most part. Predominantly the legacy.

CHAIRMAN WEISENMILLER: What sort of ratios have you seen on your solicitations?

MR. SCHOONYAN: I do not have an answer to

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that question Commissioner.

CHAIRMAN WEISENMILLER: Well, if you can get back to us in your written comments that would be good.

MR. SCHOONYAN: Right. And we do plan on filing fairly detailed written comments.

CHAIRMAN WEISENMILLER: Thanks. Jim?

MR. AVERY: Good morning. My name is Jim Avery. I am the Senior Vice President of Power Supply for San Diego Gas & Electric Company. I'll try not to repeat some of the comments you've already heard and I'll just touch on some other issues that I think are important.

Right now, currently, SDG&E secures about 15, 14.6 percent of our resources from a distributed nature within our county. The balance of our resources, right now the largest share comes from out of state. And over the next 10 years we expect that number is diminish significantly as we replace them with contracts coming online within San Diego and Imperial Valley and predominantly most of our new resources are coming in through Imperial Valley. As you know our Sunrise Powerlink is well into construction and is targeted to be in service by the summer of next year. And will be the transmission highway to provide access to renewable resources. From our standpoint, SDG&E follows and believes very strongly in pursuing the loading order of pursuing energy efficiency demand response first, then we look at renewables in our county, then we look for renewables within the Imperial Valley and elsewhere within the state and only after we exhaust those avenues do we look beyond those borders into other regions.

There are some significant challenges within SDG&E service territory. Right now, we represent less than 10 percent of the state's portfolio and yet we do have some challenges on what does that mean for deliverability within our system. If you look within San Diego and if you take, for example, Michael Picker's 2,000 megawatts of distributed generation within San Diego, you add on top of that 1,700 megawatts that the ISO is planning on connecting to the Sunrise Powerlink, you add on other generations such as combined heat and power, other qualifying facilities, and fossil generation that must run within San Diego in order to provide stability, and you're going to find in the Spring and Fall on Sundays at noon time and Saturdays at noon time, the system is going to want to push thousands of megawatts North through our system because our total system load in 2020 on these time periods in peak conditions during the Fall and the Spring, our loads are only going to be about 2,500 megawatts. Yet, if you add all of the generation that's going to be intermittent connected to our system, wanting to flow through our system, there's no other place but for it to flow North into the LA basin. There's a limitation on that corridor today. That corridor when San Onofre is running is only 400 megawatts of excess room. There is no physical room to put these resources in our basin so that creates a major challenge for us.

Another major challenge that we face is we finance the bulk of our distribution and transmission system, utilizing industrial development bonds. These industrial development bonds come with restrictions as to what we can do with operation of our system. Which means we cannot build our system any sooner, or greater or larger than we need for our native load system which means that we cannot be a hub in San Diego for people building generation with the intent to serve it elsewhere in the state without putting our bonds in jeopardy. And to give you a range of magnitude, our industrial development bonds cost on average roughly 200 basis points below other market costs so it is a significant opportunity for our customers, a significant cost savings to our customers and it is something that we are deeply concerned about.

There's also another thing that we cannot forget and that is the inclusion of distributed generation does not mean that there is an avoidance of transmission. You need transmission in order to integrate the system and balance the system and provide stability for the system. So just by adding distributed generation does not mean that there is or you could avoid transmission expansion in order to satisfy that distribution need. And that's no small charge. It can be and will be significant if we don't do this in the right way.

Now the approach that San Diego has taken, I mentioned earlier that we do give preference for resources that can connect to our system on the distribution level within San Diego. Over the last several months, we have announced over 80 megawatts of new solar contracts that will be connected to our distribution system. But we've given emphasis for those projects that can connect directly to our substation so we can avoid massive distribution upgrades and we will be announcing, in the next couple of weeks, a series of contracts as almost as twice as much as what we just announced in the last couple of months. So we do see that there is an opportunity to do this but the approach we've taken is to make sure that it's integrated into our system in such a fashion that does not require major transmission or distribution upgrades to accommodate. Thank you.

CHAIRMAN WEISENMILLER: Actually, I need to remind everyone to speak into the microphone. I guess we now have the overflow in the other room. And unless you're really in the microphone they won't hear it.

I guess, Jim, the two questions I have for you – one was when you talk about most of your resources being distributed, what definition were you using?

MR. AVERY: Well, generation that can connect to our distribution system or distribution substations anywhere within the San Diego load basin. We are a very capacity constrained region and for us, anything that can connect to our distribution substations I would consider to be a distributed resource.

CHAIRMAN WEISENMILLER: Okay. So distribution connection, good. And the other question, I think probably for people in general, would you give a brief explanation of the two county rule for the IDBs?

MR. AVERY: The IRS basically mandates that any entity that utilizes industrial development bonds must utilize those resources solely for the benefit of the county and perhaps one neighboring county. We cannot extend beyond that region. For San Diego, our counties are San Diego and Southern Orange County. That means in the prohibition on the bonds basically say that we cannot build our system no sooner, no greater, or larger than what is required to satisfy our local distribution need.

In other words, we cannot expand our system for the benefit of serving the LA Basin for example. That would be viewed as a violation of those bonds. In addition to that, we cannot be a net exporter for the purpose of satisfying or serving load beyond the San Diego and Southern Orange County regions. Now there are provisions that allow us to do certain transactions that might be economy in nature but it cannot be built with the purpose of satisfying something beyond the San Diego need.

CHAIRMAN WEISENMILLER: Right. And again for people general information, the City of San Diego issued the bonds so it’s their credit that’s tied up in this and if SDG&E were to violate this then the bonds would lose their tax exempt status and this phenomenal economic impacts to the bond holders. So anyway, I’ve testified on this in the merger case so it is a serious issue.

I guess the last issue for Jim is what has been your experience on the SDG&E PV program?

MR. AVERY: Well, we haven’t been allowed to issue the RFO at this stage but we're anticipating we'll be anticipating the RFI I believe it's later this week which will be in conjunction with the overall RFO for resources. Our RFO, the solar energy program, is a little bit different than that that was structured by Edison in that we were predominantly looking for, or initiating a program, looking for ground-based systems. Although, we have then agreed to open that up to provide anybody to bid into that whether it's on rooftop, whether it's on ground mounts and it'll provide us a good opportunity to see what the relative cost differences are. Now we do have two solar programs in our company already. One of them is our sustainable communities where we have been out actually testing the market and building solar on rooftops and in addition to that we have been doing a solicitation or taking bilateral contracts for larger scale distributed generation connecting to our distribution systems. And when I say connecting to the distribution system, they can come into the substation at 12KV or they can connect in at the 69KV bus in the substation itself. But we have seen a number of very competitive bids on the distributed side connecting into our substations.

CHAIRMAN WEISENMILLER: Thanks, Jim.

COMMISSIONER PETERMAN: A quick follow-up question. Of the 80 megawatts solicitation you recently had, how much of that were projects that could connect directly to the substation?

MR. AVERY: All of those had been. They're connecting into two substations at, again, 12KV or 69 KV.

COMMISSIONER PETERMAN: And for applications that were not connecting directly to the substation, what type of price differential were you seeing?

MR. AVERY: We have not received any bids or bilateral bids of any size at this stage.

COMMISSIONER PETERMAN: Thank you.

MS. RAITT: Thank you. Next is Jim Shetler from SMUD. Thank you.

MR. SHETLER: Thank you. Good morning. My name is Jim Shetler. I'm the Assistant General Manager for Energy Supply with the Sacramento Municipal District and I'll walk through my presentation relatively quickly and I'll try not to repeat.

We are a publicly owned utility and that means we are governed by an elected Board. There's some background information here which I won't spend a lot of time on. One thing I want to make clear is that we do have very aggressive energy policy goals that have been established by our Board. We did meet our 20 percent

RPS goal and 3 percent green energy goal last year. We actually exceeded that. Our Board prior to the legislation already told us we will be 33 percent RPS by 2020. Through our existing program, we have sufficient renewables through 2016 and we have options in place that will get us to 2020. We also have very aggressive energy efficiency goals and our Board has established a greenhouse gas reduction goal. First of all, we'll meet the electric sector by 2020 but our other goal is to decrease our 1990 levels of emission by 90 percent by 2050.

In looking in how we approach things, and I want to talk about that as a publicly owned utility, we recognize we owns us as our customers. We spend a lot of time trying to understand what they want. And very clearly, they want a safe, reliable, environmentally responsible and cost-effective electric system. Our Board has directed us, in looking at those competing demands we have to come up with a sustainable approach to do that.

On the resource standpoint, looking at our current renewables. We tried to do a few things. One, balance between utility scale and distributed resources but also balance between base load and variable resources to try and minimize the impacts.

Looking at our distributed resources, obviously solar is a major player but biomass is also a player and about 200 megawatts of our renewables right now are coming from distributed resources.

From SMUD’s perspective, we’re really looking beyond 2020. We feel we aren’t going to be able to meet the renewables goals and the greenhouse goals with our existing program. So we’re very focused what happens 2020. And we’re in the process of doing an integrated resource plan and finalizing that with our Board. And we’re focused on objectives around greenhouse gas reduction for liability and renewable energy.

In looking at the results of our preliminary IRP, we’re looking at a lot more renewables coming forward, primarily central plant but we’re also looking at distributed around solar and biomass and biogas.

From the standpoint of looking at a mandate, I guess I’ll make a couple comments. First of all, SMUD’s approach is that we’d like to be told what the policy goals are, and allow us to figure out how to implement them. And we’re not overly in love with more mandates on how to get there. We also believe our existing programs will get us to 2020 so we don’t feel that there’s a need for mandates to get to 2020. We do have concern of moving too fast on standing distributed generation. We support it. We have throughout our history but we want to make sure it’s done in a sustainable manner. We have concern about the costs, both direct and indirect costs going forward. The reliability impact from both the grid operations and the distributions systems standpoint and also just a permitting and land use issue associated with starting to move in that direction. If we are going to talk about a new mandate we believe it should be based on a needs based concept to reflect the fact that we’re seeing, as many others are, zero load growth and to address the fact that we had existing accomplishments to our renewable program.

The other thing, and some others have noted this, we got a lot on our plate this decade. We’re expanding energy efficiency, we’re expanding renewables, we’re launching smart grid; we have greenhouse gas reductions and a cap-and-trade program coming our way. And I think that we need to make sure that we’ve evaluated all of this and understand the impacts before we add more uncertainty to the mix. But overall, we still support renewables. We support distributed renewables, we just want to do it in a sustainable way. Thank you.

CHAIRMAN WEISENMILLER: Yeah, Jim. Do you want to talk for a minute about your experience with feed-in tariffs?

MR. SHETLER: Ah, yes. We did launch a feed-in tariff program in January of last year. Our mandate under the state is about 30 megawatts; we did a 100 megawatt program. We wanted to see what the impacts would be. We opened it up for solicitations January 3rd and within a week we had 100 megawatts solicited—more than 100 megawatts solicited. And we did the feed-in tariff kind of with a benefits-based pricing and it averaged around 14 cents a kilowatt hour, it varied hour to hour but on average it was 14 cents a kilowatt hour. We’ve had very little withdraw from the program. The first from the major feed-in tariff projects will be coming online later this summer with the rest through next year. And right now they appear to be pretty well worked their way through the permitting process and will be starting the construction later this month and early next month.

CHAIRMAN WEISENMILLER: Great. And what sort of interconnection issues have you found with them?

MR. SHETLER: Well, one of the things we did do when we put our feed-in tariff program together, we had our distribution services group look at what circuits would have the last impact on us and we made that information available to the developers. So they did review that. In general, we haven’t seen a lot of impact. WE have had a couple of areas where we will need to do upgrades to the system in order to accommodate. And for our program, that saved developer costs similar to what you heard from San Diego as a public entity our bonds are revenue based and tax exempt and we have to use that money towards serving our customer. So for individual impacts that a developer might make, we require that the developer pay for that. But overall no major impacts and we’re able to accommodate it.

CHAIRMAN WEISENMILLER: Okay. Last question is do you want to talk about your experience with solar highway?

MR. SHETLER: Well, if we can get through a couple of negotiations with an entity called the State of California we might find out.

(LAUGHTER)

MR. SHETLER: We’re in the middle of—we do have an R&D project underway, it’s about one-and-a-half megawatts located in two locations, one along Highway 50 not too far from the SMUD headquarters, and then a little further out Highway 50 near a little town called Rancho Cordova on your way to the foothills. We’re in

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the middle of going through the CEQUA process, we're finalizing the CEQUA document and bringing that to our Board in the next month. We have had a bunch of public outreach with both the two cities involved, the City of Sacramento and the City of Rancho Cordova. In general, we have gotten a lot of public support for the project. It's interesting negotiating with Caltrans, let's put it that way, and we're working our way through that and hopefully once we get the lease agreements finalized we'll be going forward later this year with online probably next year.

COMMISSIONER PETERMAN: The final question on your feed-in tariff program, so to focus on areas where there's preferable circuits, how did that effect your geographical distribution of projects?

MR. SHETLER: It just turned out that most of the favorable circuits tended to be rural where there was low load on them already and that's most of the projects in the southern part of Sacramento County. So if you're familiar with Sacramento, Elk Grove, Galt areas with the projects ended up.

CHAIRMAN WEISENMILLER: Thanks. Jeanne?

MS. CLINTON: Good morning. I'm Jeanne Clinton with the Energy Division at the Public Utilities Commission in San Francisco.

For the benefit of the Commissioners and Advisors behind me, there’s a sheet that looks like this (holds up document) that was at this corner, if you could pass those down you’ll have the handout that I’m using for those of you in the audience it was a one page legal size sheet.

I’m going to start by focusing on the procurement mechanisms we have in place to encourage distributed generation both at the system side and on the customers side. I’m not going to go through each of these. I think the information is self-explanatory.

The points that I would like to make is that perhaps we have three families of procurement mechanisms. One family is exclusively for renewables on the supply side such as feed-in tariff, renewable options mechanisms and the solar utility-owned solar PV. Then we have a middle category which is sort of a hybrid category of qualifying facilities and heat and power projects, which may or may not be renewable and which may or may not be DG depending on the size of the facility. But they do include substantial maps of DG and a significant portion of renewables. But they’re a unique animal as a result of 30+ years of PURPA history. And then we have the customer side generation which we currently incentive through our CSI, the California

Solar Initiative, and the Self-Generation Incentive program.

I would also point out that when the SGIP program began it was primarily fossil-based distributed generation technology and the objective was to reduce peak demand. It then migrated to legislative direction to be a renewables only program excluding any fossil and now we’re under another legislative mandate to return consideration of fossil-based technologies if they’re clean and meet certain greenhouse gas emission reductions. So that has been a bit of a roller coaster over time in terms of what technologies and fuels and performance characteristics are acceptable or not.

The important take away from this menu of mechanisms that we have in place today, which are administered by the investor-owned utilities is that we have between 6-7,000 megawatts of distributed generation, either developed or authorized to be developed through this existing mechanisms.

Now I want to turn my attention to how do we figure out how much more can be integrated into the procurement system for the investor-owned utilities. We have a process that we work on with the utilities and many stakeholders called the Long-term Procurement Planning Process, LTPP, and that process goes through a somewhat complicated modeling and analysis process to figure out what are the best ways to lineup the resources to meet the expected energy demand in California and specifically for the investor-owned utilities. The factors that that process considers is economics, the timing of resources and the reliability of resources, what might be necessary in supplemental resources to firm up say an intermittent resource. We also look at grid-integration issues. Location factors, environmental and greenhouse gas factors. And in the case of CHP, we are of course also looking at the implications of avoiding fossil fuel use for the heat that's avoided as a result of the CHP process.

So right now that process is underway. One of the scenarios that we're looking at is looking at an additional 9,000 megawatts of DG on the supply side, separate from the CSI and SGIP program.

Besides that LTPP process, which we have parallel studies and policy proceedings underway on interconnection issues. The two primary processes that we're involved with are the Renewable Distributed Energy Collaborative, also known as Re-DEC, and the Role 21 Working Group Process. And in those processes, issues of interconnection are looking at both "Can we identify preferred locations?" "Can we streamline the process for getting analysis and acceptance (inaudible) interconnections?" "Can we better understand the investment needs necessary to accept the generation interconnections?" and "How to allocate any costs associated with that." And then more specifically in the case of solar PV through our separate CSI and RD&D program, we have spent a fair amount of attention focusing on grid integration issues as well as other issues and specifically have supported projects to look at high-penetration and solar PV and what that would mean for integration at the system level. So that's sort of the lay of the land at the analysis in planning front. I expect that these proceedings will enable us to make determinations at the PUC on appropriate targets and procurements strategies going forward, beyond those that we have already committed to.

I would like to sum up just by indicating some of the questions that I think that we're looking forward to answering. First on economics, at what price or what subsidy will we be wanting to accept renewables and renewable DG. Secondly, in the case of reliability how do we match the availability of these resources with the demand for energy and look at what kind of firming resources might be needed as companions to these. Third, in the area of interconnection there's a tremendous amount of work that needs to be done to improve our knowledge and be able to figure out how to update standards for interconnections, how to have better predictive tools, how to streamline procedures that were not necessarily put in place to consider thousands of systems at the 1-20 megawatt level and to understand the factors that are driving the costs of interconnection and then how to either minimize those costs or allocate those costs.

So those are the kind of questions we’re contemplating.

CHAIRMAN WEISENMILLER: Jeanne, thank you very much for coming up. The one thing that I was going to flag for you was for the upcoming panel on the KEMA analysis of Europe, it seemed like one of the big differences is the European requirements for having some sort of metering on projects over say, 100 kilowatts, to provide some sort of visibility more to the system operator of what’s really going on. I don’t know if that’s tee’d up at this point. I guess there’s also—another KEMA key difference between California and Europe I guess is the ability to curtail projects, again, by the system operator on the need for reliability. I don’t know if those sort of issues have been discussed or if the PUC has had a chance to look at the KEMA study yet.

MS. CLINTON: Well, I think our staff has looked at the KEMA study, I haven’t myself. But in the question of metering, in CSI and SGIP, we already require metering. That’s on the customer side. And of course you would have metering on any wholesale side. So we have production or performance metering required at least down to the 10 KW level on solar PV and below 10 KW it depends on the cost of the feasibility. We thought from the beginning of the solar program that it was essential to have the customer have a feedback loop to know how their system is performing.

CHAIRMAN WEISENMILLER: Right.

COMMISSIONER PETERMAN: Jeanne, the 9,000 megawatts in the LTTP that you referenced that you identified, these megawatts then that will be funded through all the other programs besides CSI and SGIP?

MS. CLINTON: The 9,000 megawatts are all on the supply side so they’re not on the customer side, so CSI and SGIP would be separate. This is sort of a planning study, this is one of several scenarios. There’s not really a commitment yet to fund the 9,000 megawatts, it’s one of the scenarios being looked at in the long-term procurement plan and that process will inform us for the different scenarios which are optimizing cost, timing, environmental considerations and things like that, what are the tradeoffs and choices.

COMMISSIONER PETERMAN: So that would be 9,000 megawatts of DG, correct? I just wanted to make sure I understood that.

MS. CLINTON: Yes.

COMMISSIONER PETERMAN: Thank you.

MR. LONG: Okay. So assuming I can hop in?

MS. RAITT: Go right ahead.

MR. LONG: My name is Noah Long. I'm representing the Natural Resource Defense Council, pinch-hitting for Carl Zichella who had a scheduling conflict so I hope you'll understand the replacement, the last minute replacement. And I'll try and just address a couple of the questions and thoughts we have on this.

First, I'll just say that I really appreciate and NRDC really appreciates the statewide focus— increased statewide focus on both renewable energy generally as well as distributed renewable generation. The signing of the 33 percent RPS recently is a huge milestone and, I think, everybody in this room can really appreciate that. And it's great to see this administration not just sign that bill but move the ball forward with further commitments to this area and the fact that there's so many folks in this room and even a spill over room and folks on the phone, really is a great sign of a thriving industry and better times yet to come for renewable energy generally as well distributed renewable generation.

That said, I want to take a little bit of a step back and take a look at how distributed generation fits into our goals of meeting the renewable energy commitments already on the books as well as our larger goals of reducing local pollution as well as greenhouse gas emissions from generational electricity. I think in order to set the right regional goals, which is the focus of this panel as well as the right statewide goals for distributed renewable generation, we really need to take a focus at what the kinds of benefits are that we hope to achieve from use of distributed renewable generation or for that matter any renewable generation. There can be some areas of overlap, obviously, in terms of benefit from distributed and large scale and in some ways, some of the costs can also overlap. So to assume because it's DG there will be no land use conflict, for example, I think would be an inappropriate assumption; to assume that the system costs of integration will be lower may be true but not always true. So I think to the extent that we can keep those in mind, we'll be set better goals but also set better milestones in terms of getting those goals enacted.

Location matters. And of course that's true with both large scale and small scale renewable generation. And to the extent that we can set these goals with those planning processes at the same time so we're considering both not just how much but where we want to focus these generation and the characteristics of the generation we want, I think we'll be in a better place to say that it's these targets.

Distributed renewable generation isn't necessarily going to have, like I said, less land-use benefits if you have lots and lots of small projects out in the desert they're going to have very similar impact in terms of land-use as a few really big projects. So we want these small projects, less than 20 megawatts is often the sort of shorthand for DG, to also be cited in places that reduce the system costs that reduce the transmission needs and also reduce the land-use impacts.

I think, to some extent, we can try to 'hurry up and wait' and get a lot of projects signed up but then have to make sure that the interconnection process goes smoothly or wait to make sure that the land-use citing process goes smoothly and then put a lot of excess pressure on those processes because we didn't think about them in the first place when setting either the statewide or the regional goal.

So that said, I think that it's great to have an additional distributed generation goal for 2020. I think we should also be thinking about where we want to be before 2020 so the interim goals between now and 2020 as well as what the long terms are—goals are beyond 2020. 2020 is—you know we started talking about the 33 percent RPS by 2020 some years ago and now 2020 is a little bit closer and now I think we can start talking about the goals that stretch beyond 2020 like the gentleman from SMUD was talking about.

I just want to say a couple more things which is there was also a question to the panel about what sorts of additional programs might be necessary. I think from the very helpful chart here from the PUC you can see if we are serious about increasing the amount of distributed generation after 12,000 megawatts - whether it's by 2020, or before 2020, or after 2020 - we are going to need more programs, I think, to the extent that we are going to have greater procurement programs, we should integrate those into other planning processes and the barriers that the folks at PG&E and others were talking about but also build on the successes of the existing programs. Some of these programs are really quite successful. Some of them are just getting started, the reverse auction mechanism is a really exciting program, I think, that a lot of folks in this room and around the country are really excited about. We should build on what we learn from those project programs in order to increase the procurement side as well.

I guess the last thing I'll say in summing up is that these regional goals should be a starting place for developing the right state goals because the whole benefit of distributed generation is that is has local benefits and reduces some of the both timing considerations and the land use impacts. So to the extent that we're developing a statewide goal we should do some of that and use some of the analysis that's already been done to build that goal from the bottom up both in terms of timing and finality. With that, I will leave it to the rest of the panel members. Thanks very much.

CHAIRMAN WEISENMILLER: Yeah, Noah, thanks very much. I have a couple of questions. Obviously your colleagues Carl and Joanna really gave a lot of thought as far as the ready process to environmental screening of the larger scale projects. I don't know how far you've gone in terms of thinking about similar environmental screening or weighting factors for the distributed projects.

MR. LONG: My understanding is that the ready process didn't go as far into that. They did take a little look, and Carl mentioned this to me, how long it would take to meet 33 percent through the CSI and I think it was something like 100 years. I guess our view is that a lot of those screening process--screens should probably be the same. As far as larger projects, there may be system benefits but, like I said, a lot of 20 megawatt projects can end up taking up the same amount of land and have the same conflict. Potential land conflicts of a large project. And also that's true as far as where it's located. Being on the distribution grid may imply being closer to load but doesn't necessarily imply less land use conflict.

CHAIRMAN WEISENMILLER: Exactly. In that context I think there's a lot of emphasis and I think Carl and Joanna are using disturbed land and so the question in part is how much should we be focusing on disturbed land as opposed to, say, rooftops.

MR. LONG: Right. And I would say in either of those before places that are not (indiscernible). And I think that has to be part of a bottom up analysis.

And you know some of that analysis has happened at the PUC and I believe here as well to look at where are the rooftops, how much rooftops are we talking about. And then if you screen that by integration requirements of the circuits that they will be going on to I think that has a pretty big limiting factor, at least on the low cost, low hanging fruit DG. Going on to disturbed lands increases the amount of total megawatts we can put on considerably but even still 12, 000 megawatts is a lot and it's going to take up a lot of space. So I don't think that we can assume it will all be rooftop and disturbed land. And I think, as a result, we're going to want to start taking a serious look in the beginning at the kinds of environmental screens that we want to make sure that we're locating with the lowest impact.

CHAIRMAN WEISENMILLER: Exactly. So I guess part of the question is trying to make sure that somehow we tee up the activity to come up with the environmental screens as early as possible opposed to say the permit processes are wrapping up to a decision and somehow discovering as you said location really matter.

MR. LONG: Right. Thanks.

CHAIRMAN WEISENMILLER: Next.

MS. RAITT: Nicole?

MS. CAPRETZ: My name is Nicole Capretz. I'm with the Environmental Health Coalition. And first we just want to thank the Commission and the Governor’s Office for giving our communities a voice and as importantly giving us a seat at the table.

I do have a quick PowerPoint. I’m going to kind of digress away from the high-level technical conversation and just kind of focus in what’s happening on the ground in our communities just so we can see how people are being directly impacted by these programs. Next slide please.

Environmental Health is a 30 year old grassroots based organization in San Diego. We build grassroots campaigns to improve the health of children, family, neighborhoods and the natural environment in San Diego and the Tijuana region. We are also part of a statewide coalition called CEJA, California Environmental Justice Alliance; we are a coalition of base building organizations and there’s six of us kind of representing different geographic areas of the state from North to South to inland. And kind of one of our biggest success stories thus far is the, we believe, is a really instrumental role we played in defeating Prop 23. We contacted, along with environmental justice organizations, over 250,000 people of color. As everybody knows, the people of color vote was truly instrumental vote was truly instrumental in defeating Prop 23.

So needless to say our communities are really excited about the opportunities that are presented by distributed generation but what's really pivotal for us is making sure that we develop programs and policies that integrate our community members.

So just quickly, next slide, I'm doing my presentation in tandem with Bill Gallegos, who's also a member of CEJA's Communities for Better Environments. I'm going to quickly go over what's at stake for our communities in these programs, what's the solutions and then I have a quick video of some of our community members because, again, we really wanted to drive it down to the ground and the perspective of people who are living in communities that often don't get the benefits in these new technologies.

So what's at stake? As most of you know our communities, unfortunately, by income level alone are surrounded by a lot of polluting activities, freeways, oil refineries, diesel equipment, buses, trucks, they have high asthma rates, high poverty levels and high unemployment which obviously is being exacerbated by the current economic situation. And again, I'm from San Diego, so just looking at San Diego numbers we have 10 percent unemployment, in our communities it’s 16-20 percent. Our community members, frankly to the Commissioners, are really counting on you. They really, really are counting on you to be a voice for them and to make sure that they’re needs and opportunities are considered. And unfortunately, the future doesn’t look any better for the communities that we serve. Obviously, we have all the existing conditions but report after report repeats and reminds us that things— the communities that we serve are going to suffer the worst impacts from climate change. We really have to equip our community members to be prepared.

And so really quickly, obviously some of the impacts are the heat island effect because there’s not a lot of green canopy. What you see is a lot of concrete and asphalt which just exacerbates when heat waves start coming in, next slide—

Lack of air conditioning, the cost of air conditioning, lack of transportation, increased air pollution and higher asthma rates. So there’s a lot at stake here and so again that’s kind of way we appreciate the opportunity to be here.

So the solution is really investment, it’s investment. Clean energy investment in our economy, our communities and what jobs we can bring into our

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communities. I mean it’s interesting to sit here and hear all the utilities about all the barriers and all of the costs, but the question from our communities is: “What’s the cost of not doing this? “What’s the cost of not investing in communities in rarely get investment?” And so that’s the frame we’re coming from when we hear those conversations. Because, look, the benefit of if we do invest in these communities in terms of cleaning the air, providing jobs, making their homes healthy and a lot of the intangibles of neighborhood revitalization and just feeling control over their future. Having control over their energy sources. And bringing money into the community, often these communities see a lot of money going out and obviously that’s true for most of us as ratepayers that we don’t generate our own source of energy so we spend a lot of money on assets outside of our region. But what are the possibilities? Like what is the vision that could occur if we actually started investing in these communities? So we kind of are hoping that the utilities take a wider frame as they’re evaluating where they’re going to be investing their distributed generation resources.

And I don’t want to suggest that there’s nothing going on because there have been a lot of training programs even in our communities and we are grateful for that because of the stimulus package. So we have a lot of trained workers but here's the really disheartening part, because I actually speak at one of the training programs, is that there are no jobs. So here we have some of these community members that are very excited and really feeling like this is a new opportunity but then they get trained and they have nowhere to go. And I think there's nothing more demoralizing than getting someone's hopes up and kind of having them dashed.

So again, trained workers but few jobs. Solar is still not accessible to a majority of low and I would even say low-moderate income residences. And the utilities—I want to more speak for my experience from San Diego, from our experience still going for larger scale solar. We're still not seeing investment in our communities even if there's some distributed generation resources that are going in San Diego County they're not going into the communities we serve.

And then here's just a map. It's a map that I use often in San Diego to kind of capture what's happening. We have SDG&E's renewable energy which one percent is in our county and I don't know how much percent of that is even in the communities we serve. I know they're trying to improve on that but we still have a major imbalance and we'd like to help change that.

And then this next slide kind of captures where all the solar is in San Diego and the darker the area on the map, the more solar they have. Our communities are outlined in green so that's the kind of light shade of yellow which again reinforces the trend that solar distributed generation is not being invested in the lower income communities.

And then finally this is just a quote. We're surrounded by freeways, our children have asthma, invest in redevelopment to clean up our community. And so to just drive that point home we did interview a few of our community's members.

(VIDEO SHOWN)

MS. CAPRETZ: That's it, thank you.

CHAIRMAN WEISENMILLER: Thank you very much for coming today and also for pulling together the videos for us. Obviously, a lot of hearings we look at sort of the technical side of stuff in terms of grid interconnection, or we look at the program side of stuff. It's always good to have more connection into the communities that are affected by our energy choices.

I think in terms of a couple of follow-ups, one thing I was going to suggest if you get a chance to talk to Jeanne Clinton. I know that PUC has a low income component to the CSI Program, one they're certainly trying to extend and expand and certainly there may be ways that that program can reach out to your community.

The other thing that I was trying to figure out was, in the connect of the early 2000s period, San Diego communities under SANDAG had pulled together a community plan for energy and part of the question is it's probably time to revisit that and look at it more in terms of merging distributed gen and how that can fit in. I'd certainly encourage you with Jim and everyone as you're taking the plan flight home to sort of continue the dialog from today and figure out what is the plan for San Diego. Obviously we're trying to move forward but I think, as Michael Picker indicated, it's sort of good not to just have the top down but much more the community-based planning and so we can try to connect those through this process but certainly trying to move forward on that would help.

MS. CAPRETZ: Yeah, I appreciate that.

CHAIRMAN WEISENMILLER: And just finally, just to flow everyone, one of the things that'd be good following up on Noah's suggestion community wise where you prefer not to have these admittedly cleaner technologies but still all energy production that involve some environmental impacts. So trying to figure out how, again, during this screening upfront so we're not marching down the road and we've reached a number of dead ends.

MS. CAPRETZ: Great, thank you. We're fortunate because the author of the Community Power Board is here, Bill Powers. And the only downside to the low income program of CSI and you know there's a lot of great aspects about it but you do need to be a homeowner. So unfortunately for a lot of our community members that leaves them out. It is a great program.

COMMISSIONER PETERMAN: Nicole? Following up on Chair Weisenmiller comments regarding preferred locations for the DG. I'd also be interested in having more information about fossil fuel generation in your communities relative to the larger utility service area. Thanks.

MR. GALLEGOS: Good morning. My name is Bill Gallegos. I'm from Communities for a Better Environment. We're a statewide environmental justice organization and we're part of the California Justice Alliance. I noticed that so far only Nicole and I are smiling. I have to say that when we start talking to our community member about this possibility for distributed generation they kind of respond out of feign or the name of the great Etta James song “At Last” because it seems like now there’s an opportunity to get something very, very positive from our energy infrastructure because pretty much they feel like they’ve had the consequences of—the negative consequences of our fossil fuel infrastructure. So this is something that’s really right on-time and it has a number of wins for everyone, improving our air quality, healthy economic growth which we desperately need as Nicole pointed out in her presentation. Our communities were in recession before there was a recession and now it’s been doubled up. So there’s a very, very serious situation in which we not only have wealth lost with high mortgage foreclosures, small business failure, high unemployment rates. People are just getting hammered and they feel like they need a lifeline and I think we’re here to say that—and I think on behalf of the California Environmental Justice Alliance, we want to work with you on designing this project so it really has a benefit for the communities most in need and the state as a whole.

And I’m also not going to go on the technical side because that’s not my area of expertise but we want to share some recommendations that we hope will be considered as you’re designing this program.

First of all, I think, we want to be certain that 12,000 megawatts really means 12,000 megawatts. The goal of this program, as conceived by Governor Brown, as described by the overview of this workshop is to develop “a renewable strategic plan to identity challenges and strategies to achieving Governor Brown’s Clean Energy Jobs Plans Goal of adding 20,000 megawatts of renewable generating capacity to the California system.” We would disagree with folks from the utilities who say that we should not have a clear target with clear timelines. We think there should be a definite target of 2020 is a good one. There was quite a bit of thought that went into the consideration of the RPS bill was being considered and we think that we need a program with firm targets, not soft targets that will never be achieved because that’s the unfortunate history with our previous efforts of achieving renewable energy.

Secondly, we should acknowledge the 12,000 megawatts of renewable generating capacity is reasonable and doable. We already have 6,000 megawatts of distributed generation programs and this is a solid foundation so let’s build upon it. California has wisely decided that we need to increase our renewable portfolio standard to 33 percent and if we are thoughtful and creative we can achieve this ambitious goal through the development of a range of solar technologies – solar, wind and fuel cells. Technological developments make our task reasonable, affordable and feasible.

And thirdly, let’s make sure to get things right. We must design a program that products genuine renewable distributed generation. For instance the program would get off to the entirely wrong foot, in our opinion, if the state adopts the utility proposal to include the combined heat and power as a renewable. CHP targets currently being considered would take up nearly all of the remaining capacity above the 6,000 existing renewable DG programs. So let’s keep our eyes on the prize and not exclude renewables from the governor’s increased target. Furthermore we need to ensure that most of our renewable portfolio benefits local communities and is not primarily located in remote sites that require the construction of expensive and wasteful transmission projects. We should create a program that emphasizes small scale renewables so that benefits accrued to our poor, inner-city and rural communities.

Concretely, we recommend that two-thirds of this new project be established and commercial and residential buildings or parking lots and one-third from ground-mounted locations. By the way this is completely in-line with the recent recommendations from the LA Business Council, one of our nontraditional allies. And, of course, we will need to create policy mechanisms to make small scale work which include revamping the California Solar Initiative to capture more low income homes and adopt a feed-in tariff that can make small scale projects affordable and effective. And I would say that if we're going to think out of the box, let's really think of something that I know never gets considered and I know is a huge challenge we should think about when we talk about needs based. Let's retire these old facilities. They're poisoning our communities. They cause enormous health problems. They're inefficient. They're wasteful. So let's see if we can connect these two things - the building of this new infrastructure with getting rid of the old one.

Fourth, we need to establish a fair allocation of regional targets, if we do so we will be assured that all parts of the state will benefit, not simply our wealthiest communities. Actually the Governor's proposed allocation seems like a good initial estimate. But the current gross estimate megawatt targets are too general to make certain that we meet the social, economic and environmental justice goals that should be central to this program. Let's not make the same mistakes that we made with the CSI program which really marginalized those concerns.

Fifth, community participation is essential to the success of this program. You can see from Nicole's video, and we can make that video in every low income community in California, folks want to participate. They want to help make this happen. We would like to see a robust community participation component to help make sure that local distributed generation really is constructed and that these projects are in accordance with the real needs of each community. We would like to see the Commission take the lead in designing this program and we would recommend that the Governor, who's an activist, play an active role in ensuring that the PUC carries out its implementation as intended.

Sixth, we recognize the technical challenges to increasing renewable distributed generation and we are fully aware that utility companies always insist that it cannot be done and we heard that this morning, just one barrier after another. We disagree with this pessimistic and even self-serving assessment. I can assure you that the environmental justice community is in this process for the long haul and we want to work with the CEC in this to help address the technical and institutional challenges in a way that improves reliability, minimizes cost and protects the environment. We can do it. Energy storage, demand controls that other feasible measures which we will be glad to share with the Commission, can reduce the need for fossil fuel and increase the potential for integrating renewable distributed generation. This is what California needs. It's what the planet needs and it is what our communities need.

And I want to just close by saying that the farm workers movement created a phrase that captures this optimistic spirit better than any other – Sí, se puede.

CHAIRMAN WEISENMILLER: Thank you for your comments. And thank you for participating today. Certainly, we're hoping that this, again, kicks off the dialogue both here and in the communities.

MR. GALLEGOS: And as our former Governor said, we'll be back.

CHAIRMAN WEISENMILLER: Next?

MR. POWERS: Thank you. Bill Powers, independent energy consultant, San Diego. Thank you for inviting me to be here. I am going to say a few positive words about rooftop solar.

First, I'd like to see who has solar on their rooftop? Good, that's a good sign. And I want to thank the Governor’s Office for allocating 2,000 megawatts of distributed renewables to San Diego. I’m sure that SDG&E shares my excitement about that allocation. I do though want to point out the Governor’s office to again recognize Jim’s statement this isn’t happening in a vacuum. For example, in San Diego we do have a two million dollar transmission line that has been permitted and approved under the idea that we will be bringing our solar energy in from afar. I do disagree though that it’s a done deal. There was an adjunction meeting on a transmission line on Monday that’s been postponed so we don’t know where that’s going to go. But the argument that has been raised is one that I had not heard before. Because we have a transmission project in the works, this cannot happen, that we cannot do this level of distributed generation in San Diego or in another situation, I suppose, where we have this. I think that this is really the ball game and the Governor’s Office should be aware of that. I’m glad we’re having this discussion.

The comment about the PUC and the Re-DEC process is one of the options that were looked at which is called the High DG option, 15,000 megawatts of distributed PV instead of essentially all of the solar coming in from remote utility scale sites on transmission lines and one of the—it’s striking to look at the graphics for that because what disappears are the transmission lines. And so that’s really a lot of what we’re talking about.

It looks like I may have been the only one who went through the questions that Heather asked so I will, since I did that, now go through this.

First off, the suggested methodology for interim and regional targets. A great document that has come out of the utilities and they did it jointly, PG&E, SCE and SDG&E, was The Energy Efficiency Strategic Plan. That plan has very ambitious targets for energy efficiency and for photovoltaics in California we identify rooftop solar as energy efficiency measure. Number one in the energy action plan. And that document does include targets for existing residential and existing commercial. And I did run the numbers which I show on the answer to the first question. And based on my calculations if we do what we say we’re going to do, and this isn’t just a guidelines this is approved rule making at the PUC, we will need to put in somewhere between 12 and 15,000 megawatts of PV on rooftops to fulfill our obligation to the Energy Efficiency Strategic Plan.

And I disagree that rooftop solar, even on

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residential rooftops, is more expensive than business as usual. All of the residential IOU customers who are using a considerable amount of electricity pay in the range of 30 cents per kilowatt hour or more for a significant amount of the photovoltaic electricity that they use. Those, again, running the numbers on the quantity of these so-called tier three customers that are paying 30 cents a kilowatt hour or more, we can put in approximately 12,000 megawatts of PV over the next ten years and that would essentially push out these high tiered customers and that is cost effective today to do that on residential rooftops.

The other issue that Lawrence Berkeley National Labs came up with a report a month ago where they pointed out the obvious. You invest 15 or 20,000 dollars in a solar system on your home, the next day that home is worth 15 to 20,000 dollars more money and that one of the unfortunate developments in Berkeley they developed a Property Assessed Clean Energy That Pays program, great program, got stalled for reasons that are still unclear. But one of the issues is that the lender couldn't recover the money from the use for this PV system if the house had to be sold under unfavorable conditions. But the fact that the home's value increases at least on par with the PV that went into it is a critical piece of information.

Getting to Number Two, Rule 21 restriction on DG inflows, the KEMA report on what’s going on in Germany, I thought was exactly on point. The Germans are doing what we said we’d be doing here years ago. In fact, the California Energy Commission in the 2007 IEPR said given that the utilities are spending two-thirds of their capital budgets on the distribution systems, on upgrades and new substations, everyone of those upgrades at substations should be to make those substations smart grid compatible, which means the flow can go both ways. We don’t need Rule 21 anymore. Those substations can handle flows, they’re monitoring the flows, they’re monitoring inverters, they know what’s happening. And that’s what’s going on in Germany. I think that the SEC representative was exactly right. Yes, the utilities need to know where the DG is coming from. They need to monitor it in real time. They need to have the capability to shut it down, if they have to in an emergency for perturbation but that is relatively easy to do and we just need to do it instead of continuing to talk about doing it.

CHAIRMAN WEISENMILLER: Bill, one thing. Given the time, I think you can assume we’re going to read all the comments so if you can hit the high points that would be great.

MR. POWERS: The third high point is that we talked about the cost of this. We don't know the cost of the alternatives. We don't know what the cost of the contracts are for the big solar. We don't know what the contract costs are for the gas turbines. We do know based on Green Rush that was produced by the DRA, that we're now six billion dollars over what's called the above market funds. We have to have transparency in these contract costs or we can't really say whether or not one option is more cost effective than another.

One thing, I think, that we also need is I don't see us getting very far if the utilities retained administrative responsibility for either energy efficiency programs or for feed-in tariff programs. That simply has not worked. It is not moving forward. The utilities are signing contracts for utility scaled solar at above market rates, I think at PG&E that 77 percent of their contracts are above market rates yet we're holding CHP. We're holding PV to 10 cents less per kilowatt hour and that, just in my professional opinion, the value to the utilities the so-called avoided cost to PV is at least 20 cents a kilowatt hour. If we are designing our feed-in tariff programs like the LA Business Council program in that range, we will have a dramatic expansion of PV. If we hold these feed-in tariff rates at 10 cents a kilowatt hour we will get no PV out of these programs.

And to conclude, what I'd like to do if we can go to the next slide, is what I would like California to be in 2020 is what Germany is in 2011. This is a download that I did Friday and the slide that is the first slide shows a yellow crown. Well that's the Germany electricity demand on Friday and noon to 1 o'clock they were getting 22 percent of their entire electricity supply from primarily rooftop PV. That day it was not a perfectly clear day in Germany. This slide to the right is showing an orange swath in Western Germany as cloud cover. And down below, what I found striking about the German data, is what I think is exactly what happens in California on summer days. We don't have clouds in the load centers so we get all the solar that we have installed when we need it, which is during the top 100, 200 hours of peak demand. What we don't get is the wind power. Germany has twice as much wind power as they have solar. And this is not to scale, the lower right is the wind power. Twenty-seven thousand megawatts of wind power but less than a thousand at peak on this particular day. This isn't definitive for all days in Germany. That is the value proposition. When the solar is in, you don't need gas turbines to back it up. It will provide reliable power and at least the reliability of the peaking gas turbine. But if you're relying heavily on wind power you need to back it up. I think that one thing that will hopefully come out of this discussion is coherent loading order for renewable energy. Why we do what we do for economic reasons. Thank you.

CHAIRMAN WEISENMILLER: Bill, couple of questions. If you look back at Nicole's slide on the sort of area, where she's trying to focus at least some development, do you have a sense of in a community what are the best—in her community what are the best locations for the distributed gen?

MR. POWERS: In very low?

CHAIRMAN WEISENMILLER: Yes.

MR. POWERS: Commissioner, I don't have specific locations but again to commend SDG&E they headed an excellent effort five years ago to inventory every rooftop with a GIS system to partition the solar. I don't see that neighborhood as that different from some other mixed industrial residential. There are plenty of good commercial rooftops on a smaller scale in National City. There are also some substantial parking lots. It also goes right down to the water. And so, as

I recall, there are some pretty good sized parking lots. I would expect the split to be maybe a third residential, two-thirds commercial rooftop parking lot.

CHAIRMAN WEISENMILLER: Okay. I guess the last question is that you talked about peakers and the one issue for San Diego is a lot of the power comes in on SWIPL and can be knocked out or can be knocked out by fires. And so the question is assuming that we lose one of those line after midnight, how would you back that up at this stage to do the 1,000 megawatts in 10 minutes?

MR. POWERS: You actually bring up a wonderful question about utility planning. What has happened in the last 25 years is that we have gone transmission heavy and generation light. And one of the reasons we got into trouble in 2007 during the fires and those transmission lines were cut, and that was happening during the day as well as during the evening, is that we did not have enough local generation of any kind to cover us at a time of modest load. So it’s not so much of an issue of PV. The solar coming from the desert isn’t going to be there at night either so it’s not a question of whether it’s PV in the desert or PV in San Diego. It’s a question of not having enough load in San Diego of any kind to cover us in times of emergencies.

CHAIRMAN WEISENMILLER: Any questions?

MR. POWERS: I should say generation of load.

CHAIRMAN WEISENMILLER: Mary, go ahead.

MS. LESLIE: Yes. Thank you. My name is Mary Leslie. I'm President of the Los Angeles Business Council and I'd like to thank the Commission for inviting me here today. Heather, I feel like I owe you answers to your questions specifically.

But meanwhile, I'd like to share with you some of the research that we've done and the policy recommendations we're making at the local level. We're also working with Michael Picker on the goals he's assigned us. Those aggressive goals for the City and County of Los Angeles because we think that a lot of the work we've done has regional application.

To begin with I should say the Los Angeles Business Council is a group of predominantly industrial, commercial, retail owners of property citywide in Los Angeles. They're large owners. But we also represent a lot of large non-profits like hospitals and schools. And we've done a lot of work with LA USD, LA CCD and our major universities. With that those are the different hats that I have on. We've also done a lot of work in the affordable housing area for years on workforce housing issues. That becomes relevant in a minute when we talk about our solar rooftop potential.

We started really the last eight or nine years really working with our then new Mayor with some really aggressive clean energy goals. And then got really involved in establishing some green building codes and energy efficiency. Wes see that as the first line of defense on all of the things you're trying to accomplish.

However, our Mayor almost two years ago issued the LA solar energy plan. I don't know if you've seen it but it represents a vision for over a gigawatt of solar energy for LA from the Department of Water and Power. And in it, it contains 150 megawatts of solar FIT. We really as a business group tracking these issues had no idea what a solar feed-in tariff was and whether or not that we would be interested in it. So we engaged in some research and we found that the Energy Commission had done a study in '08—back in November '08 encouraging that if you were interested in a solar feed-in tariff, I think Karen might have been there when this was occurring, Commissioner Douglas, that you had to go through kind of a rigorous investigation of how to develop an indigenous feed-in tariff based on what was going on in your community. The KEMA report that you issued, we actually used it as an outline, I don't know if people tell you that, we actually did. And the reason we did was because it was really difficult getting at the data sources that we needed to make a decision. So we also entered into a partnership with our university, with University—UCLA and their public policy school and we engaged an economist to work with us because the key to the feed-in tariff is of course what you're going to pay. In addition to what the availability was and at what price you could deliver it.

So we did many studies, actually three last year. We did the first one on what the design of the feed-in tariff would look like which we can make available to you all. Then what the price would be based on the design and the availability of our rooftop space. Just this year, we went a little bit deeper and engaged another university, USC this time with UCLA, to take a look at the equity issues around solar. Because it became very apparent to us because solar was for something that people owned and then other people were not participating in the program. So we were very interested in that. We were also very interested in that from the perspective of a gigawatt and a half solar rooftop potential we saw on multi-family rooftops, apartment buildings. That got into the work we did on workforce housing.

We have a new study, we just released it, called Making a Market regarding these issues. And this research is really pretty interesting. Unfortunately, I don’t have the slides for it but I can send them to you. What it shows is that some of the best rooftop potential in the City of LA is in the lowest income areas. And that starts to make sense to you because if you think about it, in LA 1.7 million of residents are renters and they live in about 96 percent of the apartment buildings are for renters. Much of which is low income and they have the largest, biggest flat roofs. Wealthier people tend to live in condos that have smaller roofs, with less solar potential. So, this is a very interesting study because it says four places in LA really work – central LA, Korea Town, Westlake and the Valley. So it’s a very nice distribution as well for our city.

So with that, I’d like to turn to for a minute, and excuse the presentation of this because we are partnered with academics so you’ll still see it says teach, so you’ll see that the way this is structured is posing a question and then answering it. The motivation for us, I should say as well, is really the economic development implications of this policy because we are a business group. We wanted to know whether or not if this was an opportunity for businesses to invest. Another way to meet energy efficiency goals, Bill I liked what you said that these are inner energy efficiency goals. And then, as I said, what policy could we be advocating for that could make a difference in LA.

So with that, I don’t really need to go through the basics with this group. You know what a feed-in tariff is. Next. Next. And we are always explaining what a feed-in tariff is, we really don’t like the name. In fact, we have gone to Clean Energy Solar for the Ground because we did a lot of research. We actually commissioned a poll by Richard Mullen that looked at what the support for a solar policy would be in LA and were ratepayers willing to pay more. And by the way, 80 percent of LA Angelinos are willing to pay more, up to one dollar more a month which is really important data we think for our council people who will help decide.

So here’s the solar feed-in tarff. You know, basically you have the ability now to generate energy off your rooftop and sell it back directly to the grid at a price. Next.

We also have to explain it relative to what net metering is because of course we always have a very large net metering program in Los Angeles. What we like best about the FIT is that it allows you to maximize your rooftop potential. You don't just put up as much solar as you need, right. You actually expand to how much solar you're capable of. Next. Next.

We looked at the benefits of the FIT because we wanted to see whether this was really worthwhile as a policy objective in LA. We think there's tremendous economic development benefits in terms of investments. Thanks to the federal tax credits there is much to be gained, and we'll show you the numbers later, in addition to we made a commitment to a clean tech corridor and clean tech in Los Angeles to grow our economy. We're at 15 percent unemployment right now. It represents billions in new investment. It represents an ability for people trained in our communities to have jobs. It helps us meet our RPS goals. It reduces our outer basin transmission requirements and cost. Next.

In terms of the local development and the job creation. This is something that's really discussed a lot in Los Angeles. How do you know that people are actually going to get these jobs. So we spent some time on what these solar job chain looks like and so this is just identifying all the sorts of jobs, and for most of our analysis we don't even count the manufacturing jobs because we're not counting on those. We're assuming PV is going to be purchased elsewhere. So we're really just focusing on the construction, installation and what little maintenance there is of the systems. Next.

In Los Angeles, where we came down with UCLA is that our criteria for solar feed-in tariff program is that it would be cost effective and provide a savings over time. As we've discussed today here already is what will ratepayers be willing to pay and can you show that renewable programs can be cost effective. The magic number for us was 600 megawatts. That's 600 megawatts over a 10 year program which is really, of course, a 30 year program. That's where you can say the program is cost-effective and provides a savings over time and that will show you how we got to that. But meanwhile, we live in a political world of what can we do that and when can we do it first. The Mayor's initial program of a gigawatt of solar, the 150 megawatts of solar feed-in tariff can be done without any grid upgrades. So this is something that our Department of Water and Power can do now. We've been using that number. We've also been using that number relative to the federal tax credits that run out in 2016 because we want to maximize the federal tax credits. So you can see that we designed a program that incentivizes at different program levels different costs, and I'll show you those. We also designed a program that really will emphasize large commercial, industrial and multi-family apartment buildings with much less emphasis on residential homes which is really covered under SIP and CSI. We also are advocating that we get the program going now, this year. We don’t really want to—we’ve been discussing this program for two years. We would like a program up and running this year, which I think we have now both the leadership in the Council and the Mayor agreeing to this would be SB 32. That’s the program that we’re—which will be our pre-program pilot.

You can see here on the 150 megawatt program what the implications are – private investment would be over 500 million. That we would reevaluate the program every one to two years to reset the price. That the program would need to have an easy application process. We did an analysis of all the solar FIT programs in North America for best practices that we can also share with you. The simple application, the transparent fare and the timely manner in which the program is administered is critical. We know that there will be over 4,500 direct jobs created from a program like this. And we know that we’ll reduce, at least, 2.2 million metric tons of CO2. This will also power over 34,000 homes in Los Angeles, just 150 megawatt program by 2016. Next.

One of our major investment groups did the analysis on the 600 megawatt program over 10 years and, again, this shows you the solar chain. And it also shows you where the investment is. So from an economic development standpoint, this is a multi-billion dollar program to the City of Los Angeles. It would not be insignificant. Next.

We did an analysis of the different systems at the different levels and what the tariff level would need to be. There's a lot of data behind this work. What we came up with is that 19 cents is kind of a magic number. That 19 cents is starting to be a number we think that will really incentivize the large scale roofs and the large multi-family rooftops, that we can do both at this number. Next.

As I said before, in addition to the federal tax credits, you have the depreciation as well and then many of these projects we're talking about would be in an enterprise zones so you get an additional 10 percent. So you could almost have 50 percent of your solar installation paid for if you do this in a timely manner. I would encourage timeliness from an economic development standpoint is to be noted here. Next.

I think I've reviewed all the reasons why we think that this is a good idea. Now the multi-family housing this is really the surprise of the initial studies of last year. Just how large this is of a sector and how many people you can reach. So we started to analyze the different ways this is presented. And of course is the CPUC areas, you have programs like MASH and Virtual Net Metering. These are programs we do not have in the municipal areas. We wish we had these programs in the municipal area. We are working with our department on ideas on how to do this. I think that there is an interest in seeing how they could do this, particularly in the pre-pilot program. Next.

Okay. The physical potential. We worked with the County of Los Angeles, with the GIS mapping, we ran it through the parcel tax, we know the age, we know a lot about these buildings. We know that there’s 19 gigawatts of solar potential in LA County, which is a huge amount of potential. We know the way it’s distributed by the different utility districts. This is what you’ll see up here. Edison having the lion’s share, Department of Water and Power having half as much and then Vernon and the others having less. Next.

We know in the City of LA that over 2 gigawatts is commercial and industrial. Almost 1.7, 1,700 megawatts is single family, 1,400 is multi-family and then 156 megawatts of government non-profit. Next.

The mapping is interesting for the county. There are very easy ways to determine where the optimum areas are. Next.

We started to overlay them with the economic development maps. You can see the enterprise zones on top of where the solar rooftops potential is. Next.

We've broken it down by our council districts. Each of our council people know where their best solar potential is, their largest projects. With this, it actually tells you for LA what I said earlier. That the Valley, the San Fernando Valley in Los Angeles, and the downtown and along the Alameda Corridor are all rich areas for solar. Next.

We did an analysis of the tariff pricing where we would reach grid parity on the costs. Our initial analysis was around nine years depending on at any given time what was going on with natural gas and other sources this number moves. But the fact that you can get to parity is what's important. Next.

We looked at the ratepayer impact. You can see here that initially you pay more but that over time you pay less. So from the ratepayer's perspective this is a much better deal than what has potentially be represented to them. We've had a lot of great conversations in Los Angeles and all of them associated with renewables have been negative. Particularly the ones we had last year over the ECAP increase. I don’t know if any of you followed it in Los Angeles but it was pretty horrendous. It was almost as if all renewables were responsible for all increases so that was unfortunate. But through education, we can explain this over time that this is not true and that this can actually be beneficial to you over time. Next.

As I said before, this is the impact to the ratepayer. Obviously, not everyone will solar so some people will be paying into a program that they may or may not be using. However, Angelinos who like solar, which 80 percent do, are willing to pay more even if they don’t personally benefit from it. We’re very happy with that outcome. Next.

I’m not going to belabor these but these are actually cost analysis by the size of systems. We do do this because it explains to owners how it would work. Next.

This is a large commercial system. Next.

As you can see the price of installation—and as you can see, these are high. These were done over a year ago. All of these numbers are actually all lower now. But you can see that this system will pay for itself and actually payback. Next.

This is a smaller commercial system, same thing. Next.

And then this is the coalition that we formed that is extremely diverse in businesses, educational, environmental, labor and also elected officials that are supporting our 150 megawatt feed-in tariff program and 600 megawatts in our IRP, our long term IRP, by 2020. And then our shorter term goal of having a program, the SB 32 program up and running this year.

Okay. Thank you.

CHAIRMAN WEISENMILLER: I guess the question I was going to ask you was that my impression was that LA had suspended this whole program due to great popularity. You want to discuss that?

MS. LESLIE: Our CSI program? Or SIP program.

CHAIRMAN WEISENMILLER: Yes.

MS. LESLIE: They’ve suspended it for 90 days because they were so oversubscribed. They have 50 kilowatts of solar currently committed. What they did is they let the program run but without payment. So you were notified that if you wanted to have the solar incentive, you would be given it, but you wouldn’t be paid back for 1-5 years. Something to that effect. So that is the SIP program in Los Angeles and it is oversubscribed.

CHAIRMAN WEISENMILLER: Next, Heather.

COMMISSIONER PETERMAN: I just wanted to make one extra point. In your written comments, it would be nice to see more detail on the 12 kilowatt residential system, where there's not a separate slide for in the presentation. Thanks.

MS. SANDERS: Good morning. My name is Heather Sanders. I'm with the California Independent System Operator. We're responsible for the reliable cost-effective operation of the transmission system. So I appreciate the opportunity to come and provide our perspective on distributed generation.

Wow. What a great time to be in this industry. I really enjoyed hearing all the different perspectives. As Noah pointed it, it's important for us to think about the kinds of benefits that we could get. You know, contributing to the 33 percent renewables goals. The expectation about reducing environmental impact. Creating jobs and enabling the consumer to take an active role in managing their costs.

And as we work together to achieve this, and I think we need to, because we all depend on where we are bring a unique perspective. We need to take a deliberate approach. We need to respect the constraints. And we need to seek to, and I think we'd all agree to this, in putting this out there we need to seek to maximize the distributed generation that we get. We don't have to compromise reliability. I mean the worst possible case is that we put it all out there and it doesn't get us what we expect.

Finally, we do this in the most cost-effective way possible. And I think each person that has spoken with has given some ideas about how to do that. If we think about that priority, maximizing output, reducing environmental impact, not compromising reliability and minimizing cost we could get incentives created or adjusted that would align with us. There's additional benefits in taking a prioritized approach in that we learn as we go. We need to understand, this is complex, this changes how we've done this in the past. I think several people have talked about that and so we need to think about how we're going to get the information from these entities, do we need control, how are we going to back them up. It is a local problem as well. Michael Picker picked out a number of things in looking at this problem.

I've heard a lot about location and if we want to maximize the output of this generation location does matter. So what information do we need to think about those goals? One of things is that there's a lot of information out there about solar irradiance, where’s the best place to put these things. There’s also, I would expect, some information about environmental impacts where again, locationally, would the least impact be.

The component that the ISO can contribute to the most is the cost. There are a lot of costs associated with doing this and this has been hit on as well by different entities. Maintaining the reliability and trying to minimize cost are very interrelated. We can all think about that this system was designed in a particular way that didn’t have local generation so we can—it makes sense that upgrades are going to be required once we do this. I think we all understand that. And I think it’s important that we all understand the components of that upgrade. From a system operator perspective, and I’ll talk a lot more about this in the second panel when we talk about the technical considerations, but from a system operator perspective, we need to make sure that we know where this is, how it’s going to impact the system, we can see it, we can dispatch it. And then, also, how it feeds back into the transmission system.

One of the things that’s interesting about this is that we have a lot of places that we can put it, we have to update the distribution systems to support it. But then this generation's coming back on the system in a way that it wasn't designed for or is expected. We also have a lot of renewable generation coming on to the bulk transmission system. We need to understand where this is coming, it's going to change the power flows on the system especially in areas of significant constraints right now, we need to understand that component along with this. It's all connected.

Just my thought it, as Jim Shetler pointed out, there's got to be a way that with the knowledge of where the best solar places are, minimizing environmental impact, and then also input from the distribution system owners and operators from an upgrade cost perspective. We could prioritize our approach to this. It sounds like SMUD has done this a bit in their first round of this. What we really want to avoid, again, as I said is a scenario where we do contribute to the 33 percent, we minimize environmental impact, we allow customers to participate in lowering their energy costs only to increase that delivery component so much and also increase the overall system cost in terms of operating reserve and load following and backup generation that has to be there to ensure reliability. So this is something that as a system operator we look at when we're doing studies looking at the transmission planning side.

Again, the distributed generation changes where the source of our energy comes from. We will need, as we do on the transmission system, the ability to know where these are, forecast for them, understand for them, adjust our reserve requirements for them, to make sure in the event that there are clouds. Or again there are technical challenges. The way that the inverters are set up now that is if you have a fault on the system all of those inverters are currently, according to standards, supposed to switch off. If you have 12,000 megawatts of distributed generation of PV or 8,000 or whatever it is and it all goes away at once, that all has to be replaced. Depending on where it is it can cause—a fault on a distribution system can cascade all the way back up to the transmission system. Thinking about all of these things together, where's the best place from a solar perspective, minimizing environmental impacts, and then also understanding all those different cost components. It's not a simple answer. I think that with the people that we have here we can put those things together and get to an organized approach. Most of what I've said here has already been said. I'll talk a lot more about the technical aspects in the other panel but I just really appreciate the opportunity to be here and talk about it from a transmission system operator perspective.

CHAIRMAN WEISENMILLER: Well, thank you very much for attending. I'd like to again thank the panel and remind everyone that we do need comments followed along Heather's questions. And certainly as part of that, encourage people to file comments reflecting on the panel discussion today. If we had more time, I would do a round robin but we really have to move on to the KEMA speaker who has limited time available. I do want to leave time for public comment.

MS. KOROSEC: Yes, given the shortage of seats in the room I suggest the panel go ahead and stay where you are for now. So next we have Christian Hewicker from KEMA.

MR. HEWICKER: Good morning. Although from my side, it's getting close to 9 p.m. but I hope I won't fall asleep during the next half an hour or so. I will try to give you a bit of overview of the more technical aspects of the situation with regards to renewable or distributed renewables in Germany and Spain, in particular.

Maybe just a few brief comments on the front. First of all, my main responsibility within Europe is to lead our European activities in the areas of market regulations and most of my work is actually related to the market design of issues around scarce electricity markets however much of my work is also related to the technical aspects with regard to network operation and system operation but obviously for this work we work with a number of colleagues from Germany and Spain. If you have any more detailed questions afterwards, I hope that I will be able to respond to them but please do take into account that I'm not a day-to-day network planner or system dispatcher.

Also since we just the comments from the California ISO, I briefly wanted to point out that we are here and very thankful for the invitation not only by the California Energy Commission but also by the California Independent System Operator because actually the work we've done was done jointly with both institutions.

Now let's me see. Did I get it started? Yep. So I will effectively comment on a few of the pages and try to give you a bit of the story before then focusing on some of the major conclusions afterwards.

Just as a background, just an overview, as I said that we're going to speak about Germany and Spain today so two of the larger countries are you can see here not only in terms of geography but also in terms of population and load growth. So in total, they've got something like 130 gigawatts capacity, Germany being significantly larger than Spain. But what is quite important afterwards, once we talk about system operator reserves, I mean both of these countries are fairly large. Spain is electrically just about the same size as California. Germany is obviously significantly larger. But the two of them are part of the UCTE, which is the interconnected power system in continental Europe and often one of the largest interconnected systems in the world. So just the two systems together are just about a third of UCTE. This actually means that both of them are integrated at a very large interconnected synchronized power system which obviously makes a lot of things in terms of system control and frequency control a lot easier than a smaller system. So for instance if you compare to the situation of the U.K. or Great Britain and the all Irish market and island systems, they obviously much quicker faced with certain issues which also do appear in Spain or Germany but which are not yet as prevalent there.

Also to just give you an indication, unfortunately for some reason we didn't manage to put up the numbers here, but just to give you an indication here for Spain we are talking about a system of round about 90 gigawatts of installed capacity with a peak load of 50 gigawatts. The bar on the right hand side, you can see, the green part the renewables, or the new renewables as this would say excluding traditional hydro that is about 25 gigawatts including 20 gigawatts of wind and almost 5 gigawatts of solar. This is more than 50 percent capacity wise of Spanish peak load. In Germany you can also see there is some 50 gigawatts of renewables by now, largely 30 gigawatts of wind or by now actually more. We are getting closer to 20 gigawatts of solar. You're obviously talking here today about the 12 gigawatts of renewables goal by 2020 or let's say in this decade. Now just about a month ago, the German Renewables Energy Act had its 10th anniversary and so effectively what you can see on the right-hand side that capacity was more or less all built in the last 10 years. Very few of this was available 10 years ago. It was mentioned before that much of this was wind but for instance if you take a look at Germany's 18 gigawatts of capacity which we are approaching to at the moment, most of this actually was built in the last two to three years. You can really see the way you design the feed-in tariffs and the way that they are structured and all the feed-in tariffs but also interconnection issues. This can really lead to an explosion of the development. There's a number of other countries like for instance the Czech Republic which is a smaller country of something like 6-8 million people. Just two years ago after they set the feed-in tariffs too high within one year they had more than 1,500 megawatts of capacity so they very rapidly scratched the regime because they thought it was just too costly and we've seen some of these things happen in other European countries.

Another brief comment on the similarities and differences between these two European countries, Germany and Spain on the one side, and California on the other side. I don't want to go into the details about all the different voltage levels but you can see by and large they are more than comparable between Germany, Spain and California. Obviously the individual nominal voltages are slightly different. You can also obviously see that fences in California seem to have far more voltage levels especially at the medium voltage level. This used to be the same in Germany but, for instance, over the last 10-20 years the German utilities have spent a lot in standardizing it and phasing out some of these voltage levels. What, however, you can see that probably on average we are more using slightly higher voltage levels instead of the medium voltage levels than what is obviously prevalent here.

And when we talk about distributed generation it varies a bit by the different countries but in general what you can say in Europe when we talk about distributed generation is everything that is connected by distribution or more specifically medium and low voltage networks. Take into account that for instance in Germany the high voltage networks are considered to be part of distribution as well.

Now a little bit more technical background on just comparison between Europe on the one side and California on the other side. These are just two typical network designs of medium voltage networks in Germany. I don't want to go into detail. They obviously look slightly different whether in Germany, whether you're in rural areas or urban areas. They also look different in Spain. The basic principle and that is as far as I know the same in California that sometimes they are quite often operated in a radar manner or simply they are almost stretched in a way that you do have closed loops so that you can always ensure your supply from two different points so that you abide by the N-1 principle and that you can assure very high reliability. This more or less is the same between all through countries but it is different at the low voltage level.

In this case if you take a look at California, Spain and the rural parts of Germany you, by and large, have radial networks so which means that every customer only have a single connection to the grid. If this connection fails, not only the connection but also the line to the next transformer point, if this one fails you're out of power. But if you go into the urban areas in Germany you can actually supply a large part of the population. This also includes some semi-urban areas and also the larger villages, etc. Then typically you still find some sort of true meshed low voltage so which means the in the urban areas, where most of the population is living, you still have alternative supplies for customers which is one of the factors explaining on one hand higher grid costs but also explaining like why German for instance from a European perspective has one of the highest reliability—let's say network reliabilities compared to other countries. For instance, if you compare Germany to Spain German customers are used to a much higher reliability than Spanish customers. This is obviously one of the reasons but it also comes back when you talk about distributed generation that obviously you have more flexibility in the system and it’s also more powerful.

Another important difference is that throughout Europe, that applies to all the countries, definitely Spain and Germany that even the low voltage connections are full three-face circuits. We typically have the three-face circuits with or without a neutral face down to the individual customer connections. So for instance at my home today, I have a standard three-face connection, I actually have it within my own house, and it’s even the same if you go to rural areas. I know, for instance, that summer cottages in the former Soviet Union also they do have the three-face connection. I know that this is an important different to some parts of the U.S., including California, that quite often you only have a single face connection of the individual houses.

Now taking into account that you have relatively strong networks, despite the massive growth of renewables over the past 10 years that has only been a limited amount of problems of distribution level. However, you also need to consider that the countries have applied to different principles opposed just to that one. So for instance in Germany, you very seldom have problems so far in the urban areas. But there are two reasons for that. On the one hand, the urban areas or the urban networks are quite strong and on the other hand, well so far, most of the renewables used to be wind and we hardly have any wind in the cities. By now it has started with solar but once again with solar most of the development so far has been in the rural areas, most importantly in the South and most importantly it has been a program for farmers. If you travel through Southern Germany today you see solar PV panels more or less on every second farm, every second house in the small villages but you see very few of them in the villages.

That is one reason. On the other hand if you go to the rural areas, and in particular with the recent growth of solar PV, there have been more and more problems in rural areas in particular with voltage limits which have required sometimes quick upgrades or most importantly, let’s say that you just need to relocate the location of the interconnection point of the DG. It was mentioned here before that you could, for instance, just interconnect them to the next customer point instead of the direct service point for a customer. Or let’s say to the next higher voltage level. That is actually being done as a standard procedure in Germany. The only thing that you need to consider here that is being done in practice but because of the legal arrangements it doesn’t really matter for the customer is if you want to connect distributed generation to the network, by law, you only pay the effective or virtual cost to the closest point of common coupling which would theoretically be the closet point. However, if, for whatever reasons you need to reconnect it to a point that is further away this obviously needs to be done but then the corresponding costs are being socialized so the distribution company has to pay for these costs and then they are passed on to the distribution tariffs.

There’s a different approach or a different approach has to be taken in Spain. In Spain the utilities have been a lot more powerful. I would say that the politicians have not been as strong so they haven’t put in place a number of constrains on the amount of distributed generation that can be connected to any individual circuit or to any individual transformer which means that quite often in Spain it is not possible for a developer to directly connect to the closest point of common coupling but they have to go to a more distant point or to the next highest voltage level. So that in Spain, in contrast to Germany, the costs are actually moved to the developers and are not socialized. This has a twofold effect. First of all it’s more attractive let’s say from this perspective for developers to move these things or let’s say there’s less risk involved with investing into renewable generation in Germany. On the other hand also it has helped Spain to avoid problems with back feed. So Spain has almost no back feed issues in her distribution networks.

If you go to Germany, the situation is quite different. We have voltage issues in rural areas and rural networks. That’s one thing utilities are struggling with. I’ll come back to that later on in terms of system operation. We also see more and more of a trend toward back feed and it started actually at the high voltage and medium voltage level and right now it’s going more and more. Let’s say the low voltage networks, in principle, this can be resolved through the use of four-quadrant relays. I’ve heard this mentioned here. Quite often they are already in place there today. Sometimes they still need to be installed. What was actually interesting for me to hear that this was being considered as part of smart grids from a California perspective. From a German perspective, we would never think about this being part of smart grid. This is just standard traditional protection equipment. I mean that are just slightly different traditions on practices but what we see more and more that all these transformers needs to be replaced and this really moves up to the transmission levels offenses in the Northeast of Germany 50 hertz. The transmission operator of that region, I think in about one-third of the network design of the transmission transformer is being determined by renewable back feed instead of by supply to load.

I already mentioned that everybody let's say that renewables have priorities or even guaranteed access so the grid and this isn't only for the initial interconnection, it's also for feeding in. It actually comes back from the European Directives, one European Directive from 2009, which mandated—made it mandatory all across Europe. It used to be the case in Germany and Spain before. Renewables distributed generation has a right to be connected but they also have the right to feed into the network. Now again, you have a slight difference between the two countries. So for instance in Germany, I've already mentioned the cost of interconnection but for instance you can be curtailed by the DSO, by the distribution system operator of the distribution company. But even in that case, they can only do it if they've taken all possible measures on the network side on the market side, and if they can't avoid it, they're allowed to curtail you but they still have to pay for the energy. So effectively, as an operator of renewable generation you don’t face any financial risks again as these are socialized.

In Spain, it’s bit different. In these cases, there’s also some remuneration but in Spain it’s easier for the network operators to curtail renewable generation in generally including distributed generation.

Now having said all of that it looks quite optimistic and it’s fairly easy to integrate renewables into the system however this is more or less the status where we are now today. Looking forward into the future, we do see these investments will need to be done. These are just two examples from Germany from two recent studies. There was a high profile study done by more or less the entire industry together with the German Energy Agency and a number of German universities, etc. last year which took a look at the development mostly of wind and its impact on power system or system operation transmission over the next 10 years. They estimated that in order to integrate wind power, particularly offshore wind farms from the North Sea and the Baltic Sea, into the system Germany would need an additional 3,000 kilometers of new transmission lines meaning effectively 400 KV lines at an annual cost of about one billion Euros.

Just recently, I think, about a month ago the German Energy Association published the draft of another study which took a look not at transmission but at distribution so the full report is not yet available but they estimated that based on the future development of solar PV, there’s one governmental goal that says 30 gigawatts by 2020, there’s another one which also is included in our initial plan for the development of renewable energies for the European Union which specifics that we should have 52 gigawatts by 2020. This is what resulted of some need for somewhere between 200 and 380,000 kilometers of new high voltage and medium voltage lines that cost somewhere between 13 and 27 billion Euros so if you convert this into dollars it costs somewhere between 20 and 40 billion dollars. So even for a large country this is a significant amount of money. Obviously, you should take into account in particular for the distribution numbers these come from the industry so they might may be biased on the high side but in general there’s quite of a lot of agreement that we will need to invest a lot into our networks in order to reinforce them if you really want to go for a massive large scale and integration of distributed generation.

So what you can say also to a certain extent is that the easy part of it has already been done but now we’re increasingly getting into the more difficult part of the transition.

Now turning away from the physical network infrastructure from interconnection on system operations so what have the Spanish and German TSLs taken. The TSLs but also the distribution companies to facilitate the integration of renewabale distributed generation. First of all, there are a lot of strict requirements for remote control and / or monitoring either by the system operators or by the distribution companies. So for instance in Germany, all projects above 100 kilowatts need to be equipped with remote control. This actually applies for the distribution companies, so it’s remote control for the distribution company not by system operator. While Spain has said that all projects above 10 megawatts have to have a direct control and direct monitoring by the initial system operator.

Also, technical rules in recent years have been adjusted to mandate fault-ride-through capabilities for voltage control and to avoid voltage collapse or let’s say massive disconnection of small scale distributed generation if there are voltage problems in the grid. Initially, this started mainly with the wind power plants at the higher voltage levels. These were also supplemented by financial incentives. For instance, two years ago the latest revision of our Renewables Energy Act in Germany introduced a bonus for renewable distributed generation effectively for wind power and biomass plants which are able—you have fault-ride-through capabilities and which are able to provide corrective power control to the grid. Similar steps were also taken in Spain but in that case only as a transitional solution for old, existing wind power plants that were investing to the plants to make them capable of doing this. In Germany, actually, the trend is already moving forward. Now just last month, the requirements for the ability to provide directive power control were rolled out to the medium voltage grids, so since the first of April, this also is mandatory for all new units that are to be connected to the medium voltage grids and by summer, it is expected that similar rules will also be enacted for the low voltage grids; including the solar PV, fuel cells, etc. which means that by then probably all units will give off something like 13-14 kilowatts will have to be able to provide directive power control however it was quite interesting for me to see the numbers from LA. If you take a look in Germany I would argue that probably 99 percent or 90 percent of the installations are more on the rage of 4-10 kilowatts. Presumably, even in the future, most of the solar PV installations will not be bound by these new rules.

Another area that (indiscernible) TSLs from other countries have invested quite a lot within real-time controls and in fact in Spain they're extremely proud of their dedicated wind control center. The national system is operated by the Spanish System Operator (indiscernible). And actually what you can see in these photographs on the right-hand side you see the dedicated grid control center, CECRE, which is actually used just for wind forecasting and for running continuity real-time simulation of grid falls and analyzing the impact on the grid. On the right-hand side you see the traditional national control center for the power system; that's located not in the same building but relatively close to each other and are just supporting each other. And besides this national control center, Spain also has four regional control centers which actually for the regional generation distribution companies so they have a hierarchal structure with all the wind power plants and all the larger renewable generators above 10 megawatts being directly connected to the regional control centers which aggregate this information and provide it to the national control center.

Now obviously, as I said here, they do a lot of simulations, etc. amongst others to take a look at the reserves and frequency of control which they need. Again, if you compare it to the U.S. or to California the basic principles are by and large comparable. It is a big different. You also have frequency response. We have regulation and load following which is actually a single product for us. We also have operating reserves. It also depends a bit on the market design. In Spain, this is all being dealt with by the standard traditional products and by the regular interlay market of a mandatory pool. In Germany, where we have a financial market with self-scheduling and self-dispatch of generators so there’s no centralized control by the system operator. We only have reserves which are procured on the day ahead or even advanced. Until last year, the German system operators actually started to procure a special product for wind reserves which was for the timeframe of a few hours ahead. They are no longer allowed to do this. The regulator has told them that they must not do this. But now they have to resolve all these issues at the interlay market of the German Energy Exchange, the EX. What is quite interesting, a number of studies in recent years that took a look at the impact of renewable energies and intermittent generation reserve requirements and generally there was quite an expectation that we would need significantly more reserves and frequency controls in the years to come. So for instance, I think 4-5 years ago, there was another big study of the German Energy Agency and based on those forecasts you could estimate that by 2020 that Germany would need 5-10,000 megawatts of additional reserves to cope with all the wind and limited amount of solar at that time. Now, just in December they came up with a new study. The one that I mentioned earlier which also took a look at transmission expansion and in that one they came to the conclusion that effectively we won’t need any additional reserves at all. It seems to be a miracle but the explanation is quite easy because the only thing that they really changed were the assumptions of the forecast accuracy.

This actually comes back to the question of renewable forecasts or forecasting wind and solar power. What you can see in the top right is a figure from Spain which shows the evolution of the—or the accuracy of wind forecasts between 2008 and 2005. And also across the—with the time horizons starting with one hour ahead time forecast and up to 48 hour forecast. And what you can see is that they have made massive improvements over the recent years and have really been able to reduce forecast errors significantly. If you take a look at the German experience, it looks by and large similar. If you express this in the RSME what you can see in the table at the bottom is you see that we've got a standard deviation of the error of less than 5 percent on the day ahead, compared with something like 10-15 percent in California. Now this looks like California is far worse than Germany and Spain but to put this into perspective if you go into the other European countries they are also significantly worse than Germany and Spain which are definitely the front runners. This definitely has been a focus area of the system operators in both countries and has helped them to make it a lot easier to manage the system and to cope with all of these challenges. More recently, the German TSLs have started to invest more and more into solar power forecast and since April this year, the regulator could not mandate it but it has been something like a very strong recommendation for distribution networks to provide also similar forecasts for the regional and local distribution systems to the TSLs. By now if you go to the national scale of the solar power forecast has just about the same forecast error, the same quality as wind forecast. So this definitely has been one of the major main levels in terms of measuring the whole thing.

Now just to summarize—taking a few—summarizing a few of our observations and also some of the conclusions which one may draw. I mean as I said, distributed generation is not precisely defined in the countries but loosely defined by just everything that is connected to the medium voltage grids and below, so something like 50-80 megawatts is a bit higher in Germany than in Spain.

What we've seen so far is that network planners have not been forced to really enhance the networks dramatically as a result of the integration of distributed generation. But the situation is slowly starting to change, in particular in Germany. What they need to do is that typically network planners always need to take a global perspective. They do not only take a look at the interconnection of renewables but also of the future development of load and organization and replacement of existing grids. In both countries, these costs are more or less completely socialized. At least if it's completely on the network's side from the interconnection. If you go to Spain, as I mentioned before, the network operators have before able to shift

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the significantly larger cost to plant developers meaning in those cases where they have forced plant developers to relocate the interconnection point. Just a side note this is one of the areas that is under discussion in Spain.

Now in terms of the rules regarding reliability, this is something that I can't really assess myself so I have to believe my U.S. colleagues but it appears to be the rules in Germany and Spain arguably are at least as strict or perhaps even stricter than in California so the national operators of Germany and Spain do not accept any risk or reliability. You can see here for instance in Germany for voltage fluctuations of steady state, voltage extraction of only 2-3 percent are accepted. It used to be two percent. Now, more recently, it has been increased to three percent compared to five percent as I understand in Rule 21 here. And then as I also mentioned the four-quadrant protection systems have more or less or are becoming standard to German medium voltage substations and also let's say high voltage substations in order to allow for back feed conditions. So which is an important means of allowing for the increased integration of renewables into the distribution networks in Germany? This as we thought, and have already heard today, would obviously require some changes within California if you wanted to do the same.

Now one thing also is that TSLs and system operators in both countries have mandated a remote control and metering either for, let's say, very small systems of above 100 kilowatt or above 10 megawatts in Spain. And then in both countries, network operators are able to curtail renewables. If there are any grid reliability issues, again, the detailed ones are a bit different in Spain. They have a lot more discretion whereas in Germany they have very strong level restrictions. But on the other hand they can do it. But they've spent a lot of effort in this area in order to develop certain plans and policies, etc. so that they can also enact it and that they don't run into any legal liabilities here.

Then quite importantly besides the changes and the investments on the physical infrastructure are perhaps as least as important as have been the investments and efforts in the development application of improved analytical tools and better control systems, most importantly in renewable forecasting but also what we've seen first of all as a result of liberalization but also increasingly in recent years that the system operators are investing and are mandating dispatcher training but not so much for training the dispatchers for the daily duties on the job, that's one part of it, but also increasingly the entity is out training between different TSLs and system operators that work together to be highly interconnected to European networks, but also training the interaction between the system operator, producers and distribution networks.

One thing that I have not covered so far which is quite a lot in the discussion but which is not useful for new or incendiary technologies like for instance storage. Similar to the U.S., there's quite a bit of discussion on it, partially in the political arena and obviously in academics but so far this is not really used at all and it's not being considered as an imminent solution either in Germany or Spain. First of all because we don't need it for other reliability issues and the distribution grids and obviously because of the related cost.

I hope that this was at least something like a very quick tour through the experiences we've had and I will be happy to answer some questions.

CHAIRMAN WEISENMILLER: Thank you very much. A couple of questions. First in terms of looking, at say Germany, what's been the range of hourly ramps up or down?

MR. HEWICKER: I can’t tell you off the top of my head of the exact figures but if I’m not mistaken for wind we are talking about something like, maximum, 10-20 percent of installed capacity. Solar is obviously a bit quicker but with solar we’ve had less experience so far and also we don’t have so much visibility. Maybe one thing that I forgot to mention was that last year we had some cases that, due to the very rapid expansion of solar, the system operators did not see what happened to the distribution networks. For instance, last year what is now Tenet or formerly Eon, at some point during the year they had something like 6,000 of megawatts of uncertainty due to solar PV. Due to forecast errors, for instance, they were furcating lots of sun the next day but then there was lots of fork in the south of Germany so there was very little output. And there were few cases, for instance, in September because of such errors where they had to use all operating reserves that they had available just to compensate the forecast errors. So this was one of the reasons for the regulator to get involved, I think, in November last year and to ask the distribution companies to come up with better forecasting.

CHAIRMAN WEISENMILLER: And do you have over generation problems or how deep of an over generation problems could you have on some evenings?

MR. HEWICKER: You mean excess generation. So far, typically not that much because I think the trough load that we have in Germany is about 40-45 gigawatts. Now what do you need to consider is that obviously we do not only have the wind power but we also have nuclear and quite a bit of lignite power plants which you also can’t switch off. There’s one thing that makes life easier for Germany that we are very, very well interconnected with a number of other countries. The Netherlands, for instance, in the West of us they are fairly small but they have a similar problem but to the South we have Austria and Spain which are very well interconnected to the German market. These are hydropower systems. So what you see actually that they export to Germany during the day and they are importing during the night. So, which has actually facilitated it but we have increasingly come into such situations and the Danish, who have actually had such problems for the last six or seven years, they started with negative prices a few years back. I think a few years ago Germany made the same changes and in 2009—sorry, three years ago, we had a number of instances where we had negative prices on the market. Since then, producers have learned how to react and more recently in 2010 I think there were very few cases with very low negative prices. So it doesn't occur very often.

CHAIRMAN WEISENMILLER: Okay. My last question is here we look a lot at quote unquote smart grid as one way of easing on the distribution of DG. Have there been elements in the European systems of making the grid quote unquote smarter? And if so, what are the key ones?

MR. HEWICKER: Similar to the U.S., there's a lot discussion about smart grids and there's lots of policies about starting pilots, etc. Where the discussion and the initiatives are focusing so far is on smart metering but generally it is seen that smart metering is not directly related or doesn't really, on its own, help in facilitating the integration of distributed generation because you also need to have the other communication and etc. As far as I know, there are slightly different perceptions on what a smart grid is. For instance, we discussed about the protection relays, etc. and remote control of distribution networks and etc. Much of this is already standard in the German and Spanish networks. This is not being considered smart grid in Europe but it is more or less a common practice. Lots of the discussions on smart grid really focus on the decentralized control of load and generation. So far little of this has been implemented; it's all at the research site.

CHAIRMAN WEISENMILLER: Yeah, I was thinking about my last question. How much demand response is there in Europe, if any?

MR. HEWICKER: Depending on the countries, if you go to Norway there's a lot but that's because they have a large proportion of energy in terms of industry and they also have all electric heating and direct resistance heating. If you go to the other countries like Germany and Spain, etc. there's very little demand response. There is a little bit from more or less historic times from electric night heaters and there's a little bit from energy intensive industry. So for instance, Belgium has done quite a bit. The Netherlands and also in Germany a few industrial companies have actually entered the, what we call, balancing market which effectively is the market response services but I would argue for Germany that that is probably less than— the potential behind might be something more like a few hundred megawatts. What's actually being offered to the market is probably below 100 megawatts in Germany. If you go to Belgium, which is a 14 gigawatts system, I think they're contracted for something like 6-800 megawatts. But other than that so far there's also no demand response.

CHAIRMAN WEISENMILLER: Okay. Thank you. No questions. Thanks again. I think we need to move to the public comment now. Thanks.

COMMISSIONER PETERMAN: Thank you.

MS. KOROSEC: I've only received two cards from those who need to comments this morning that can't wait until this afternoon, one in the room and one online. In the room, Ed Murray.

MR. MURRAY: Good afternoon. Thank you Chairman and panelists. I'm Ed Murray and I'm the President of Aztec Solar, a local solar contractor and also the Treasurer of the California Solar Energy Industry's Association. I'm here today to talk about solar with the big S, including solar thermal. We seem to miss that all the time. It's kind of the fair haired stepchild of solar. So what'd I'd like to do is talk about it. And I represent solar thermal today.

Solar thermal includes water heatings, space heatings and solar cooling. The advantages of solar thermal is that there are no interconnection and therefore no grid impact. There is no impact on ratepayers individually as the rebates are spread out—or the people pay for the systems when they install them. Solar thermal reduces natural gas which unfortunately is used to create electricity in these peak power plants that we're hearing about will be using natural gas. About 90 percent of the water heating in California is heated by natural gas and so we can reduce that natural gas.

Taking from Nicole's slide on PV, solar thermal provides clean air by GHG mitigation, clean infrastructure, certainly plenty of jobs, healthy homes and money flowing into the community. Solar thermal is significant also, and I'm surprised that Christian didn't have it on his slides, it's significant in Europe and Asia, and especially in Germany. There's quite a bit of solar thermal there. It's truly the sleeping giant and we would like to include it in the 12,000 megawatt program. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

MS. KOROSEC: All right. We do have one more in the room. Bernadette Del Chiaro.

MS. DEL CHIARO: Thank you. My name is Bernadette Del Chiaro. I'm the Director of Clean Energy and Global Warming Programs with Environment California. We're a citizen funded, statewide environmental advocacy organization. I want to take a second to applaud Governor Brown. I don't this has been said yet but for having the guts and vision for putting out a big goal in distributed generation. Usually when I'm in energy forums like these, I'm the one person standing up and saying "What about distributed generation?". Here the whole day is on distributed generation so it is really great to be here and I'd like to really applaud the Governor for having that vision and putting that out there. California is ready for this. We know the public warmly embraces distributed solar power. As Nicole mentioned, our community colleagues, our technical schools, the workforce of California is embracing clean energy. And our policy makers need to catch up with the rest of the state.

So how do we do that? The question at hand, one of the big ones for today is how do we develop the planning, the regional targets and the goals. We think 12 gigawatts is more than doable and in fact it might even be low for what California can do if we put our mind to it and our policies to it. We think at least 50 percent of that goal needs to be on the customer side of the meter. That California can support 6 gigawatts of customer side solar distributed and other forms of renewable distributed generation, especially if you count the existing programs like the three megawatts from the CSI. A quick note on that, CSI to date, our analysis shows we're about 26 percent of the way toward our goal. We're probably going to get there ahead of schedule if we fix a couple of key things on the industrial side. Prices have dropped within this program 40 percent since it started. And we're likely to see residential break even. The residential market break even by 2015. And 30 percent of the country's solar companies are located in California. On to the jobs question, I just want to highlight the successes we've seen so far on the customer side of the meter. These kinds of companies employ about 30,000 people and the solar industry roughly has doubled in size in roughly the last three years. So, huge significant progress on the customer side of the meter and there's potential to do much more. If you take what we've grown, the markets grown 40 percent in the past year, if you assume we see a continued growth in the market between now and 2020 we will easily install about five gigawatts of customer side of the meter just solar PV. And that's if we don't do any additional policies to expand California's market, which we think we can do and should do.

We should minimize utility owned distributed generation. I think we've seen from the testimony this morning from the utilities themselves, it is one of the more expensive ways to go and a questionable program in and of itself. At the very least, we need to have greater transparency into those programs.

In terms of regional applications, there are really some surprising leaders when you look at where our actually market is today when it comes to distributed generation. If you assume continued growth in these regions that that growth is not going to slow down. There's no reason to think that growth would slow down in these hot regions. You would see, and going to Heather's presentation, the areas that have the greatest potential over 500 megawatts between now and 2020 actually are exceeding Los Angeles' so the South Bay, the San Jose region, the Central Valley, Merced to Bakersfield is an area of huge growth and huge potential, Sacramento and north to Redding. The North Valley as well. Marin Country and Sonoma Counties have tremendous growth. Then San Diego. The inland desert as well as the Bay Area proper, the East Bay and San Francisco. Most of them all have greater than 500 megawatts of potential, if not more.

In closing, some key points. As we look to move forward on the policy and the visioning process, we need to priority customers out of the need to maximize private investment and energy efficiency that comes along with that. We need to include solar hot water into our program. We need to look at retiring the old power plants including the nuclear power plants that will soon need to be retired once we hit the 2020 mark. We need to include greater transparency and also consistency. And one of the things that we should, as policymakers in California, is have a consistent way of analyzing the costs. Utilities often talk about the cost of ratepayer impacts of these programs but never is there a consistent way to look at the net benefits of distributed generation and net costs. A buzz word that was really popular about a year ago but I haven’t heard once today is the notion of building integrated distributed generation. I realize that the building market is somewhat at a standstill right now but it’s going to pick back up again and there’s tremendous potential to achieve cost reductions, efficiency benefits as well as just a huge market that we need to tap into. We need a medley of policies over across the street in the State House. It’s often heard that there are too many policies on distributed generation. We need a one size fits all. I couldn’t agree more with that. We need a medley of policies that support that variety of markets we have in California. We need to expand net metering. We need to get SB32, the feed-in tariff, off the ground. We need Los Angeles to get its feed-in tariff off the ground. We need a whole host of other policies to get moving so that we can get to this 12 megawatt and then some goal.

Last but not least, we need, in terms of our key policy priorities and in terms of, Commissioner you talked about environmental priorities, we need to have that as one measure. Obviously, we've brought up reliability, cost issues. One of the other things that we need to keep in mind when we develop this policy is that this is still an emerging market and we need to keep that in mind as a policy priority, that we need this market to get off its feet and sort of level the playing field between distributed generation and other renewables, as well as renewable energy compared to fossil fuels. So with that, I'll leave the rest of my comments in writing. Thank you very much for the opportunity to say something today.

CHAIRMAN WEISENMILLER: Thank you. Thank you very much for coming. We're running late.

MS. KOROSEC: I actually have one more on the phone. I'm sorry, Commissioner. Al Baez from South Coast.

MR. BAEZ: Thank you, Char Weisenmiller and Commission Board members. Good afternoon. This is Al Baez. I'm with the South Coast Air Quality Management

District. As you might be aware, we just released an RFP recently making $30 million dollars in funding available to cost-share the deployment of several megawatts of in-basin renewable distributed generation and energy storage to support electric transportation technologies. Part of the success of this RFP for the deployment of clean, renewable DG technologies depends, to a large extent, on available SGIP incentives. However, the current proposed levels are substantially lower than previous levels in terms of the dollars per watt. My question here is are there considerations for possibly increasing these new proposed levels?

CHAIRMAN WEISENMILLER: Thank you for the question. I actually was going to turn to each of my fellow agencies on the panel and give them a response to wrap up on about a minute levels so Jeanne do you want to take the first response to that comment and any other comments you want to use to summarize now.

MR. BAEZ: Thank you.

MS. CLINTON: Sure. I'll do this quickly since I wasn't forewarned we would have a wrap-up opportunity. To the question from the South Coast Air Management District on the SGIP incentives, there is a staff proposal up now following with legislation we were directed to undertake two years ago to renew and revisit

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the SGIP incentives. To make a long story short we've proposed reducing the incentive levels while broadening the range of eligible technologies and part of that is motivated by the fact that we now have a legislative sunset at the end of this calendar year for no more collection for that program. So we are trying to spread the available collection as far as possible. There is legislation pending to extend the program but we have no sense as to whether that will succeed or not. The simple answer is the staff proposal is to reduce the incentives for current levels based on quite a bit of analysis.

I guess in a way of summation, I would say that I think that a lot of folks here sound like we're all on the same page. The devils always in the details of trying to figure out how to do this integration and how to do it in a sensible manner in terms of figuring out the micro places in the grid where we can absorb DG and also figuring out how to spread the costs. I noticed the term in Europe is socializing the cost. We do have to understand that there are costs and we do need to, at least it appears that there are costs, maybe this afternoon from the R&D Panel we'll hear that there are breakthroughs where the costs can be minimized so I'm hopeful in that regard.

The one other comment that I would make is referring to some comments on multi-family housing participation in the solar program. We do have set aside for multi-family housing and also for low income single family housing, it's roughly $200 million dollars that's been set aside. It's not insignificant but at the higher levels that we're offering incentives for solar for the low income housing it doesn't go very far. It's not producing very many megawatts. We're open to ideas on how to increase funding for CSI so that we can expand that market and hopefully maybe in that legislative session this year we'll have some progress on that.

CHAIRMAN WEISENMILLER: Thanks Jeanne. Heather, do you want to say any wrap up? Michael Picker – Any wrap up? Okay. Anyone else on the panel want to do a one minute wrap-up? Okay. Thanks again.

MS. KOROSEC: We'll return at 1:30. Thank you.

[Session break. Group resumes at 1:35 p.m.]

MS. KOROSEC: All right. We're going to go ahead and get started now. It looks like the room is a little less full than it was. But just in case there's a need for overflow, we do have a second room. We lost our room across the way so it's up on the second floor up in the second floor conference room. If you go up the stairs and just go around to this side of the building, there's a big fishbowl looking room and use in there.

So we're going to start up with our discussion of European Experience in Degrading Large Amounts of DG with Heather as our moderator.

MS. RAITT: All right. Thank you. If we could hear from Jon Carruthers from PG&E that'd be great.

MR. CARRUTHERS: Good afternoon. My name is Jon Carruthers. I work for PG&E as an Electric Engineer in San Francisco. I'm in the Electric Distribution Planning and Engineering Organization. First, I'd like to thank you for allowing us the opportunity to participate in the panel. And I think it's great that the CEC contracted with KEMA to look at the experiences in Germany and Spain and start to get down to some of the technical issues so we can understand and leverage off of that kind of experience.

My comments don't focus on a particular level of megawatt penetration at the distribution level but rather, more generally, about high levels of penetration on a distribution system. But whatever the state ultimately decides, what the stakeholders ultimately decide, with amount of penetration of DG, I hope that we can continue to agree that we need to interconnect DG safely and reliably, and safely for both the public and the workers and DG installers and operators and everything like that. And that we don’t inadvertently degrade power quality or power reliability. And we should always be thinking about cost effectiveness.

The good news is that there are definitely steps that we can take to integrate more DG into distribution systems. The solutions identified by KEMA in their report that are used in both Germany and Spain are very similar if not identical to many of the solutions engineers in California would use today to integrate DG into our distribution systems. And then there’s some other elements that we could further look forward to helping the integration of DG. Namely items like smart grid, we talked about a little bit earlier, smart grid technology like Volt/VAR optimization, distribution management system programs. And then from the DG vender side, things that we can consider from an inverter based type, you know what kind of inverters are they using, what features do they bring. One element that came up in Christian’s presentation was talking about smart meters and the ability to how that might facilitate integrating DG into distribution systems and for the smart meters PG&E is installing we’ll be able to get voltage reads from them. I think it's the kind of case where more information at a detailed level, as we understand that and can synthesize it appropriately, I think that might help us understand the distribution system performance and be able to potentially integrate some more DG into the system than we otherwise might have if we did not have that kind of information. So I think that's potentially useful.

Moving on to the questions that Heather posed in her outline for the meeting today and specifically the first question with respect to how distribution systems are similar or different than from California. There are certainly some similarities. And there are certainly some things that rung a bell for me as I went through the report that KEMA had prepared. Notably, the distinction between urban and rural circuits and those kind of characteristics that present themselves; like I had mentioned previously, the technical options available to engineers for dealing with distributed generation interconnection or operational issues. And also, at some point when you desire to integrate more distribution generation into a distribution system, there will, depending on the ultimate value selected, there will be cost and they will be significant. When I look at the number from the KEMA report of about, I think it was about 200,000 kilometers of distribution line that translates to 120,000 miles. PG&E’s distribution system, total line mileage, is 140,000 roughly, just trying to kind of put thing in perspective in terms of size and thinking from that perspective.

In terms of the similarities. Yes, many of the medium voltage levels are quite similar. At PG&E, our primary voltage is 12KV. We have 21KV and we have 4 and 48KV that was mentioned in the KEMA report. What I would have liked to see in the KEMA report is a better breakdown of the voltages, how much, how prevalent. Because as it’s correctly pointed out in the report, the level of voltage does have a significant factor on how much distributed generation can be integrated into that particular circuit. The other thing from the report that I saw was a potentially big difference in really how the low voltage networks work. PG&E, most utilities I would venture to say in the United States, they’re’ really single phase and they’re smaller in nature; much smaller in nature. I wasn’t aware of how big the low voltage networks in Germany and Spain could be until I read this report. Transformer sizes for PG&E that would serve low voltage networks would typically be 25, 50, 75, 100KVA single type phase transformers. At Germany and Spain, based on the information in the report, they're like 400KVA to 1,000KVA transformers with meshed secondary in urban areas and they serve a lot of load. That makes a very significant difference from those kind of systems that might be installed behind the meter feeding some commercial applications or specifically residents and so on. That's a pretty significant different.

As I mentioned before, at least at PG&E, we certainly have a greater number of lower voltage, medium voltage circuits in the 4KV and for that that means they are less suitable for larger integration of distributed generation.

Another difference and I'm not still sure how much of an impact this is, in California the voltage limits for providing service to customers are defined by Rule 2 which is plus or minus five percent. As best as I can tell from the KEMA report in Germany, Spain and perhaps other parts of Europe as well, it's plus and minus 10 percent. So they have a bigger bandwidth in respect to the service voltage variations that customers can receive. On the other side, in the KEMA second memo report, they talk about the voltage rise allowable on medium voltage circuits saying it's two percent. No problem. I'd like to know more about how they're doing that and also the driver behind what the report inferred as a move from two to three percent, which in my mind they're using a certain amount of their service voltage bandwidth to define distribution voltage issues and they're increasing it, I would anticipate that they're increasing it, in some ways perhaps to facilitate more DG. I think at the end of the day, I think that we have to look at voltage standards, what's in California, I think we have a little bit less elbow room of what to work with from that perspective. The reference in Christian's presentation with respect to the plus and minus five percent at the point of common coupling, knowing how things work in California, I've been involved with various Rule 21 and distributed generation working groups and this and that for awhile, I bet a dime to a dollar that the plus or minus five percent just purely came out of Rule 2. I don't think there's any, to my knowledge, there's certainly a statewide requirement in terms of a voltage rise allowable in distribution—or what would be called medium voltage circuits in Germany and Spain. So I think those are kind of concerns.

Moving on to the question with respect to what challenges have European countries encountered in degrading DG. I think the challenges would be very similar. I think it's really going to be primarily a voltage issues. I think it’s primarily going to be getting through issues associated with volumes of DG on distribution circuits and making sure that all the inverters and technology work appropriately so that when we have faults on the system they’re cleared and can then get back on in a reasonable amount of time. We do not want, obviously, inadvertent 10:01:2 eyeletting or anything like that. And I think the thermal loading considerations and some of the other protection schemes stuff, that seems pretty doable and we can work around those items from a technical perspective ultimately.

But, from a technical perspective, after reading through all the KEMA stuff, I would say that I think that we’re a little behind and I’m a little concerned relative to where California’s positioned with technical requirements for connecting large amounts of DG to distribution systems as compared to Germany. I think that this is a consideration moving forward.

Finally, with respect to building out of a distribution system what can we learn there. Again, just to put it in perspective, when I first saw the question I thought, “Oh, we’re building out the distribution system.” I started thinking about the infrastructure associated with the distribution system and as I mentioned PG&E has about 140,000 line miles with 800 substations and about 3,000 circuits. In any one year, we might grow those numbers by about a percent or two, if that. Some years less, some years more. So the modifications in and of itself aren't going to come through the distribution infrastructure but have to come through other ways. I think one of those potential ways is communications. We saw in the presentation from KEMA in Germany 100KW and that was, as I understood it, remote control from distribution system operators. And then 10MW from Spain. I was kind of blown away by a couple orders of magnitude in terms of the difference in level of control. So that's really something that we're going to have to think through because we're at levels do we really need to have control at what makes economic sense from that perspective. And, then again, moving forward I think it's not so much a distribution infrastructure question, at least as we move through picking the low hanging fruit, as it will be like I said communication, programs like volt/VAR optimization software, inverter design and inverter types and then also another factor would be electronic relays. At least PG&E, they're still a lot of the old electromechanical relays and that's not going to be suitable for back feed operation to any significant degree, that's for sure. And so that would have to change as well. And that concludes my comments.

CHAIRMAN WEISENMILLER: Thank you. I guess the one question that I have for you is that all the utilities have their distribution systems which really grew a lot in the 50's and 60's and so at this point, probably since about 1998 or so, we've been going through a massive reinvestment program. In a distribution system do you have a sense of where you are in those upgrades? Or what the average age of your distribution system is, where we are in the upgrades and how much, not responding to growth, but just replacing the existing stuff to do that smartly.

MR. CARRUTHERS: In terms of age of system, I would think that the relevant elements would be, when we think about incorporating distributed generation, would be line conductors, protective equipment and transformers. And let's start at substation transformers. Yeah, PG&E has replaced older transformers over time but still the bulk of our system, at the substation transformer level, is still probably older than industry average. So that's where I put that.

Line conductors I'm less concerned about that.

Moving on to the protective relay elements, I don't have numbers in my head, but PG&E still has a

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large number of electromechanical relays and at substations we also have quite a bit of the electronic relays as well. But there’s still quite a few of the electromechanical type and I could definitely wind up seeing spending money there to accommodate DG on distribution circuits depending on the volume, the location and—on distribution systems it’s all about location, location, location, volume, type of DG and so on. The distribution system is a lot less homogenous than the transmission system.

CHAIRMAN WEISENMILLER: And I assume, the other dominant characteristics for PG&E and a lot of the utilities, is that if you look across your system, say San Francisco probably is very old vintage while if you go out to the suburbs you might have much newer circuits.

MR. CARRUTHERS: Oh, oh. Certainly. I think we would generally would find in all the urban areas of PG&E, whether they be in San Francisco, Oakland, downtown San Jose, even the cities that line the Central Valley from Stockton and Modesto, those systems that are more urbaners would generally tend to be older. That doesn’t mean that they can’t provide good service life and that DG cannot interconnect with them but I would anticipate that’s where we would find most of the older

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equipment. It's also, I would say, where we'd find most of the lower voltage, medium voltage type circuit, that 4, 4KVA circuit type of stuff.

CHAIRMAN WEISENMILLER: Thank you.

MR. CARRUTHERS: You're welcome.

MS. RAITT: Robert Woods, please.

MR. WOODS: Good afternoon. My name is Bob Woods from Southern California Edison. I'm Director of Electric System Planning. First, let me thank you for the opportunity to provide input to this program. I have to admit I was heartened when Mr. Picker commented that this program is a technical issue rather than an administrative issue.

At the outset I'd like to say that at SCE we are committed to trying to figure out how to help California achieve these targets. We've done a lot to try and work with the various agencies to try to develop the ideal location for generators and we will continue to work in that vein.

As Mr. Schoonyan indicated the best chance of achieving these program targets will require all types of resources. As we've heard, resources such a s wind and solar can actually be complimentary. So while we've heard quite a bit about adding solar to the system today we think narrowing the types of resources would actually be a mistake and would probably increase the likelihood of problems.

One point that has been made several times but bears repeating, as we found in Europe and to date in California, is when it comes to localized energy resources location is the key. You have to locate these localized energy resources where the load is, otherwise the connection costs and the transmission could actually come into play which is where it actually gets expensive.

As my role as Director of Electric System Planning, it’s my folks that do the studies. We do the system planning. I have to tell you that there’s a concern. We have so many programs going on now and trying to complete the studies on time and keep things moving have become quite a strain. To date, Edison has over 850 applications or requests for interconnections and trying to work through those is going to be a chore. We truly do not have the resources today, and it takes years to develop a good system planner. So that has to be a concern. We believe that we can get there, we want to get there but it has to be considered that this isn’t plug and play. When you put it on the distribution system you can’t just say “Okay. I’m going to connect here.” and go. It does require a study. There may be cost involved and a number of initiatives. The key point here is to integrate these resources with reliability and safety in mind.

As Chairman Weisenmiller pointed out, one of the big differences between the European model and what we have today is that the European model has actual control of the resources. They actually are able to re-dispatch and roll back and curtain. We do not have that capability. When you start looking at a smaller distribution system, as Jon indicated, we don’t have the large distribution networks that Germany has. Our typical distribution system is about 10 megawatts. That’s what we try to keep it at, at about 10 megawatts. So when you start connecting generation of 20 megawatts you’re starting to push the limits of where you can put it on the system. The interconnection costs and all that come into play.

What I think is that Jon covered most of the technical issues and safety and reliability are chief among them as my role with system planning and from that perspective that would be a quality program. Those would be considered in developing a program that we would define as a quality program. If safety and reliability are, in fact, included then we think it would be defined as a quality program. While I think it’s great to set a date for a target every time, everybody should have a target to shoot for I would strongly suggest that we focus on quality as opposed to meeting a date. Thank you.

CHAIRMAN WEISENMILLER: First, similar question. You also have an aging distribution system. In my recollection is that’s a key part of your pending GRC?

MR. WOODS: Yes, it is.

CHAIRMAN WEISENMILLER: Again, similar in terms of following back up on the PG&E commentary on which part of their system, on that distribution system, were going to be the most stressed by these transitions and where you were in terms of trying to replace or phase those along.

MR. WOODS: In our system, Long Beach is the largest city and it’s probably the oldest. We have transformers that go back 80 years there. That is an issue. To try to figure out what the average age is really would be almost impossible if you figure that Long Beach has gone through several redevelopment efforts over the years. So you could have the 20s, you could have the 60s, you could have the 90s and all of that and you will have equipment from that period. I think probably where the two areas where we’d be the most vulnerable in terms of reliability from aging infrastructure are probably the substation transformers as Jon indicated but additionally I think that it's underground cable. When they built underground cable, back in the 80s, it had a 20 years life and I think that everybody thought that 20 years was forever. Well, 20 years is a long time ago from when that cable was put in and that is a real concern because it costs a lot more to replace the cable today than it did to put in originally. Where the load is right now is in the metropolitan areas. If you were to add generation to those areas you'd have to be concerned about where you're actually connecting. The good news for Long Beach is that you have some new and some old right next to each other. But as cities have developed over the years not all of them have that meshing of the old and the new. Some of them are pretty old, such as Santa Anna, which is pretty old, and adding generation there could be very difficult with the older systems that we have.

CHAIRMAN WEISENMILLER: Obviously one of the key purposes of regulation is safety reliability along with equity issues. But having said that, one of the things that was most striking as people looked into the San Bruno incident was that one of the aspects of that was simply that PG&E had 22 planning engineers dealing with the gas system, which certainly effected the rate at which they could roll out stuff, and obviously one of the things which we're all struggling with now is why 22, why not 32 or something which could have been a more timely replacements there. So I guess the question for you is how many people do you have in system planning and how do you determine that that's enough?

MR. WOODS: That's a good question today. I can tell you that. Five years ago we would have told you that if we had 30 that would have been the right number. We're probably in excess of 50 on the transmission side alone today as a result of transmission interconnection requests and increasing mandates for reliability criteria, development and maintaining data and understanding the impacts from the various resources. But what we also have is—I have a whole group on the distribution side that works on this. Today that group that does the interconnection requests for the distribution side is nine. There years ago that was zero. So we are focusing on what resources we need and we're trying to develop an expandable group which means we don't want to go out and hire 100 people only to have to let them go in future years. What we'd like to do is to develop contract resources, try to develop part-time resources, things like that to help us handle this. But as far as exactly what the number is, we really are struggling with that as a matter of workload. I can't tell you today what the exact number is because each year it has gotten progressively worse or, I should say, the workload has gotten progressively larger and I'm not sure when that's truly going to end.

CHAIRMAN WEISENMILLER: I guess the last question I had was does Edison have a goal of its role in terms of modernizing its distribution system of when you'd want to basically be switching out all the mechanical stuff? Is it 2015, 2020, 2030. What is it?

MR. WOODS: I would say, similar to Jon, we have a lot of electromechanical relays and what we are working on is—we replace those on a, I'll say, an on-needed basis. Let's say if it makes sense to put in an electronic relay which will reduce ONM or provide some information data to the operators we would probably replace it. One example would be if you have to send out an operator to a remote area every time there's a relay or a problem that you have to check it out, it might make sense to go out and replace that with an electronic relay that feeds the data back. Where the substation is right next to the operating center, it probably makes less sense, where you can send a

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substation operator right next door to get the data that you need. The factors that we try and include in our decision are the actual condition of the equipment, the functionality of the equipment and the necessity of replacing it.

CHAIRMAN WEISENMILLER: Next.

COMMISSIONER PETERMAN: Just one follow up question. Bob, you mentioned in the beginning of your comments the length of the queue for projects planning to interconnect. Can you elaborate more on what the bottlenecks in the process are?

MR. WOODS: I'm not the contract manager but I know that a number of them have to do with getting a generator, once you've given them the information, to make a decision. There's a lot of money at stake. We give them an impact study that says you have to front this much money, if you continue for five years you'll end up getting that money back but there's a lot of hemming and hawing, there's a lot of reluctance on the part of lenders to provide money. And, quite honestly, there's a lot of negotiations saying, "Well. Maybe you should pick that up and we'll pick this up." Our system is not quite as black and white as apparently as Germany is what I gathered from the KEMA study. There's still room for negotiation. It's not uncommon to restudy something two or three times before someone signs a contract.

COMMISSIONER PETERMAN: Okay. So these are mostly cost related versus physical limitations to interconnect?

MR. WOODS: I would say, for the most part, yes.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: Yeah, just a follow up on that, what about in the transmission area we've gone, obviously, from the sequential to more of the cluster so I guess because you kept getting in this iteration process. On the distribution system how are we going there in terms of moving there more toward a cluster approach?

MR. WOODS: I think ultimately we may, in fact, get to a cluster approach depending on the magnitude of the requests that we get. As of today, we still are handling them fairly serial.

CHAIRMAN WEISENMILLER: Okay. Thanks.

MR. TORRE: I'm Bill Torre. I'm Manager in Charge of New Technology, Innovation and Development in the Electric Transmission and Distribution Engineering Group at San Diego Gas & Electric Company. Glad to be here today.

I just wanted to use as a reference the questions that were distributed for this session. The first question was how are European Electric Distribution systems similar to or different than California. In my reading of the KEMA reports, and looking at other reports related to the European system, there are some fundamental differences of our systems. One key thing that I see is that the DG is not monitored or controlled here in California and in Europe it appears that they have direct control and monitoring over the DG. I think that’s important to point out because when system operators are operating the system, if DG is going to become a more significant portion of the resources in our system they need to have that visibility of knowing how much generation is online. I think we’ve been able to get by without knowing that up until this point but as we move toward a 12,000 megawatt goal that is going to represent a significant portion of generation in California.

I think in some ways we’re playing catch-up with Germany and Spain. I noticed in the report, in the design of their networks on their distribution system, it’s a much more robust design than what we have, say, typically here in the U.S. or California. Our distribution systems are generally radial in nature.

Most of theirs in the urban areas are a meshed network both at the medium voltage and low voltage. Our systems are radial and tend to, as they go out toward the end of the circuit, the wire size tends to drop down. We had some cases where we do have loop back with ties that can feed back on a distribution circuit but you typically can only pick up a portion of the circuit, whereas their system is fully redundant and you can pick up the entire distribution circuit.

The other thing is, I think, in general is that it’s a balance between reliability and cost. They haven’t incurred tremendous cost up to this point because of the robustness of their distribution circuits. But I do know that their energy costs are quite high right now, especially as compared to our energy costs. The proposed capital cost they’ve talking about going forward is in the range of $19-40 billion dollars to go from a roughly 16 percent penetration of renewables to roughly around somewhere of 30 percent by 2020. They’re talking, at least in their report, a significant increase of cost.

With regard to the second question, what challenges have the European countries encountered as compared to what we may have to face here in California. I do notice that they have identified some pretty serious voltage regulation problems; in particular the voltage rise problem is one of their biggest issues. And we’re facing the same thing here, I’ll talk about it later in the other session, especially with PV. We have right now in our system—there is no voltage regulation or control of reactive power and so when you have high concentrations of photovoltaics in distribution circuits you get a voltage rise problem, especially during medium and low load periods. And the solar tends to peak before our system load peaks. So you get this voltage rise issue and it drives the voltages up over our CVR limits which we put in place to create energy efficiency. As a result, when you go outside that you start reducing efficiency overall for the loads and for the system losses. So it’s a concern that we have.

There could be significant increases and upgrades on our distribution and maybe even our transmission lines. The DG in Europe has frequency droop control as well as reactive power control. Our PV here, rooftop PV, conventional PV, does not have frequency droop. So an example is that if you have a frequency excursion on our system, our PV right now is designed right now to reject or disconnect from the system. Now if your DG is a substantial part of your general, let’s say 12,000 megawatts, you have a frequency excursion say where you lost a major generator or import tie and the frequency tends to drop down, you're going to get this rejection of all 12,000 megawatts of DG off the system driving the frequency down even further causing a potentially serious system stability issue. I think we need to address that.

There's also some maintenance and safety concerns that are brought up. Also, I want to mention, that we need to start looking at some changes in our regulations like W. Rule 21 that will allow us to implement some of these things like reactive power control, voltage regulation, reverse power flow. Right now, for example, on their system they've designed it so that they can have reverse power flow. As you get higher and higher levels of PV generation on the distribution system you're going to start getting reverse power flow on the system. Our systems are all designed for power to conventionally flow from the generator down to the load. We've got to make some changes there as well.

And then lastly, question nine is as California builds out the distribution system what lessons can be learned. I just think that we need to provide the proper incentives to encourage the DG to show up places locationally. Somebody mentioned location, location earlier. The closer that you can be to the substations, the less we're going to have to paying upgrading the systems. The further away you get the more you're going to have these voltage regulation issues and voltage rise issues. We need to encourage incentives for where they're located and we also have to address the issue of who pays for the cost of these transmission distribution system upgrades that are going to occur.

So I think that concludes my comments.

CHAIRMAN WEISENMILLER: Bill, thanks. I guess the couple of questions that I had. One was if we did locate the DG just at the substation do you have a sense of what that would mean in terms of technical potential as opposed to looking at a more thorough developmental process.

MR. TORRE: I think what you're asking, and we've kinda started doing this, is looking at, for example, all of our substations the capacity available and then looking at the land that's available nearby both disturbed land and undisturbed land and how much DG or PV could be installed, and how close would it be to the substation. Is that the kind of thing you're asking?

CHAIRMAN WEISENMILLER: Yes.

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MR. TORRE: We have done that and we're in the process of doing that. We don't have a complete answers at this point. We're developing maps that would have the capability of showing where the locations are and the concentrations.

CHAIRMAN WEISENMILLER: And when do you expect to have this available?

MR. TORRE: You know, I'm not sure that I have a date on that. It's being developed and reviewed right now.

CHAIRMAN WEISENMILLER: But sometime this year, maybe?

MR. TORRE: I would hope so. I would hope that it would be sometime this year.

CHAIRMAN WEISENMILLER: And similar question to that I had asked of your colleagues from PG&E and Edison in terms of the nature of your system, the age of it and characteristics.

MR. TORRE: Well, one thing I will say to that is that we have been going through a cable replacement program in our underground system. About, roughly, 65-70 percent of our distribution system is underground in San Diego, a pretty high percentage. And a lot of the cable that was installed originally was unjacketed PVC cable and we're in the process of going through and

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upgrading those systems so our underground system is gradually becoming newer and newer. Transformers are a concern on our system. Especially as we get more and more new customer loads such as electric vehicles and things like that. Our protection system on our substation, we've been changing all of our relays out—we're about halfway through so changing relays out to electronic relaying, solid state relaying. We do have a program for modernizing—we're finishing up a project called OpEx 20/20 which includes a new OMS/DMS system, a new conditioned based maintenance system that will monitor all of our transformers and substation equipment real time and evaluate so it's conditioned based maintenance and then we're putting—finishing up a new graphical information system for mapping all of our distribution facilities.

CHAIRMAN WEISENMILLER: That's good. Certainly one of the—in looking at the gas system issues one of the things that was heartening was that Sempra seems to be implementing a policy of making all of its system peaceable and certainly at this point PG&E is struggling with the 2020 stuff but again trying to get to a more proactive strategy there. So certainly would encourage people to have a proactive strategy on the distribution system.

What about in terms of your distribution planners? What's the current size of your group and how are the demands changing over time for interconnection requests?

MR. TORRE: We kind of developed some new groups dedicated to distributed renewables. We have a new group of engineers that are handling all the contracts, W DOT and FIT bids and everything. So we've kind of expanded that area. The distribution planning side is addressing mainly our existing infrastructure and meeting our system load requirements so, in some respects, in anticipation of the impacts of the FIT and the DG and the renewables, at least on a distribution side, we've basically a whole new group of engineers and managers to manage that.

CHAIRMAN WEISENMILLER: The last thing that I am going to note is that Jeanne Clinton had—when we talked about the metering limitations earlier Jeanne Clinton had noted that even for the CSI program, that PUC has a pretty extensive metering requirement. And so it would seem like that's the next step forward here would be, on the DG, to start looking at the metering and the standards as part of the Rule 21 or as a general industry standard.

MR. TORRE: And I think that I did hear her comment on that. There is metering on the DG but it’s not monitoring, per say. The European, I think that there’s a little bit of a disconnect there, the Europeans actually have tele-metering and monitoring that sends the amount of generation at a particular generation facility back to its operating center which they aggregate together and know exactly how much DG is online at any point in time. So maybe it’s semantics but the metering doesn’t necessarily have that—it’s not necessarily set up that way. For example, AMI typically doesn’t go back to the operators, it goes into a database that can be monitored and just aggregated that way for billing purposes and stuff. It’s a little bit different.

CHAIRMAN WEISENMILLER: Okay. Thanks for the clarification.

COMMISSIONER PETERMAN: One follow up clarification question Bill. Regarding your comment around the treatment of PV when we see the frequency drop, the technical fix to that – where does that lay? Is that on the distribution side, with the PV system?

MR. TORRE: I think the best place for that solution is in revisiting Rule 21 and the requirements for the generators for when they connect to our system. That they have the capability of frequency response.

That they have the capability of reactive power control. They have the capability of sending a signal to tell us how much power they're generating. They also have the ability to accept set points from the utility so that they can put in set points, that way you would have two-way communication and control for the DG. That's essentially what they have in Europe and that's what we would need, I think, especially as you would go to higher levels of DG. It becomes a significant resource.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: Yeah. Do you have a ballpark cost for that?

MR. TORRE: You know, I was afraid you were going to ask that. I did take, for example, I took what they have on page 20 in their report number of KEMA which outlines the $20-40 billion dollar number and I tried scaling that to California. I kind of hesitate telling you what I came up with because I did take, by the way I took the existing renewables – the same numbers that were used earlier – and I looked at going to the 12 gigawatt number for DG and I tried taking their numbers and scaling it just to get an idea. Just to say it's in the billions of dollars, I'll say that.

CHAIRMAN WEISENMILLER: Let's say slightly different question. Mine was more of if we were to put that type of metering on a DG system, any idea of what the cost would be for that, for say a one megawatt system?

MR. TORRE: I would say it’s in the thousands of dollars. It’s not really big dollars in terms of a burden on the DG supplier. I don’t think so because it’s not that big of a change to the inverter and the functionality and as far as control capability, I don’t think it’s that big of a change. I think that they could do it for a few thousand dollars. On the utility end, we’re going to have to make sure that we have the communication control infrastructure in place to do the communication control. So there’s cost on our end as well as on the part of the DG supplier.

COMMISSIONER PETERMAN: I would be happy to see more information about those costs in your written comments.

CHAIRMAN WEISENMILLER: Dave? Want to go next?

MR. BROWN: Good afternoon, Commissioners. I’m Dave Brown from Sacramento Municipality Utility District. I’m a Principle Distribution System Planning Engineer. Actually, one of two who does the interconnections in our company so it’s more hands-on.

I thought I’d throw up a slide here real quick that’s been really useful in explaining—this little color codes here we applied to our GIS mapping system, some of you have seen this before, and to identify where we have low costs interconnection opportunities. One of the things when you can’t decide who should be paying the costs, the easiest solution is to try and not have costs. Next slide, please.

This one might take a little bit to fire up. It’s actually from our website and you can drill down to the point on this map that I can see the court that I live on, on this map. It doesn’t have any street names, it doesn’t have any utility facilities on it at all. It was designed around some homeland security guidelines. We didn’t want to give up any information but at the same time folks could look on this and see about how big of a system they could put in without encountering any significant costs. We’ve made this available for our Feed-in tariff project and the challenge that it produced was that how many people do you think wanted to go in the purple area? Nobody went in the purple area. That’s the area that can take projects well over 5 megawatts without any real cost associated with them. Almost everybody located in the white area is to the south, that basically are the areas that wouldn’t accommodate much of anything without going onto our 69KV system and most of them did. Although, the blue areas down at the south border and the green around the towns of Galt and parts of southern Elk Grove accommodated quite a few projects at very low cost so that we were kinda of happy that they weren’t always picking the most challenging locations. Next slide.

Now this was based, not on the 15 percent, but on 100 percent of our minimum day time load. We decided to modify the 15 percent because that was from the Rule 21 working group and that was based on any technology, including those that might be on at night. We wanted to modify that to be 100 percent of our daytime load, which is something probably closer to 30 percent of our peak. That worked out reasonably well and it was based on the fact that, unlike the European models where they’re designing their substations to work in reverse, ours not only aren’t designed to work in reverse but bad things happen when they’re made to run in reverse. The bad things happen proportional to how much reverse so we figured a little inadvertent reverse, not going to be a problem for us. Luckily, we’ve got—or thankfully, we’ve got some management that will let us eh maybe every now and then be wrong. By having the flexibility of being able to go out and fix something that maybe we didn’t get right the first time we’re able to push the envelope just a little bit more than maybe we were previously.

This is just a quick printout and I had hoped that it would be large enough to read and it really isn’t. Back in March we had a real spike in applications for our net energy metering and the reason for that was that our dollar amount was running out in one of the tiers so it was going from, I think it was, about $1.80 a watt down to $1.25 a watt. Something like. And we had a lot of folks come in on that. The other thing is that a lot of people are stuck in their houses and they can’t get out of them and so they’re reinvesting in them. The other thing is that there’s no federal credits for a lot of the energy efficiency that used to be available so all the sliding salesman type folks are migrating over to solar. And it shows in the applications that we’re seeing. One of the interesting things in the upper chart, it doesn’t show, but these bars are a combination of the easy projects, the ones that you can take five minutes to do a review and the hard projects, that take considerably longer to do a review. The bottom, for the feed-in tariff, we were knocking those out, in turnaround time, of about two months. The upper projects tend to run between five minutes and an hour, except for a few exceptions. We put six megawatts in out in the Aerojet plant and we’re still working up the loose ends on that one.

The Siemens Assembly Plant here in Sacramento, they're got a two megawatt rooftop that has the distinction of being the largest, single solar pane on a roof. They extended the steel of the building when they built it to support a single lean-to. It's pretty cool looking. And then that came to the telemetry question, we're requiring telemetry at one megawatt. They put it in in three units of eight. When they were informed that that was still going to fit the requirement, then we had to go back and retrofit to get the telemetry that we're requiring.

One of the things in our larger projects, including some of our feed-in tariff projects, that is one of the things that we see from Europe is they're allowing interconnection on solar systems that are based on the 1,000 volt DC. We've got no provisions for that in the U.S., the UL requirement that most of the permitting authorities are holding these installations to, they're required a UL stamp that only goes up to 600 volts. On the ones where they're just a big old field of solar, we've talked some of the permitting agencies into letting it go if it meets the Europe standard. But we're not ready to give any advice along those lines for anything that's on a structure, an occupied structure.

That’s one place where we could go in the future.

One of the things that’s kind of exciting is that we’ve actually even done some projects with the state. I know that’s a separate matter later down the line, I’m not on that panel but we just commissioned a co-gen plant at the state heating and cooling plant. That went really smoothly. They did a wonderful job on that design. We had already integrated solar in at that site and we’re pretty happy with the way that one turned out.

We’ve done net energy metering, a surprisingly large net energy metering, like Intel up in Folsom. They took a one megawatt plant behind the meter. You’d hardly know it was there. The simplest interconnection ever. If everything went like that, this would be great. Unfortunately, the idea that we heard thrown out of looking at all the circuits and saying “What would it be if there was 15 percent on those circuits?” I don’t see, even if we could, there’s a lot of those circuits that nobody’s coming on, that nobody’s interested in sighting on. There’s no facility there. We’ve got some places where they’d like to give us a lot but we don’t have the place to take it. Van Vleck Ranch out headed towards Ione, probably a big chunk of the eastern part of the county, he’d love to give us 30 megawatts, he’s on the number six copper farm circuit and that farm circuit isn’t going to take that kind of load anytime soon and we’re really not in the business of running collector lines. Anyway, I know I’m going around in circles here but one of the things that I didn’t hear Jon mention was the network with the big N. I don’t know if you guys have ever heard about what a network is but there’s only three of them in the State of California that I know of. There’s a little one in Long Beach, there’s most of them in San Francisco and then there’s one here in Sacramento. And what they are is a highly reliable, antiquated distribution system from circa 1930-40s that will probably keep on serving reliably for another 100 years. Whenever they cut into it and take parts apart and look at it, it hasn’t aged since the day they put it in. It’s a really wonderful system except one of the features of that system is that each of the transformers is connected to the customer through a reverse power flow relay that shuts off power if power ever goes the wrong way through it. And that’s for protection because they’re delivering as many as six feeders to the customer so that if anyone shut off the customer would never know the difference. State Capital has that kind of provision. When we’ve talked to folks at the Department of General Services about the State

Capital, which by the way has a roof that is just not a good candidate, [LAUGHTER] when they took into account all of the shading, there's only about 100 KW of roof space worth bothering with and they're on a network service that has five transformers climbing off five different feeders, each protected by a network protector. So what we would do, and we've done like in the case of the CalPER's building, we just ignored that system and connected them up to a different distribution system on their solar and then just worked it out in the paper. So we've done what we call virtual net metering a number of times.

Anyway, for the first 100 megawatts that we put out in our system, we are only getting telemetry. We just want watts and vars. And what we're doing is that we're posting it on a page in the transmission system operators and distribution system operators' system—data system and they're just taking a tally. The idea is that this might be a tally that says solar or wind, biomass or natural gas. So that the operator knows that if tomorrow is going to be a cloudy day, I might take that number and say that contribution might go down. They don't really need to know, each field, what it's really going at this point. What they've told me is don't bother us until you have a couple hundred of megawatts more. And so we've instrumented the first 100 megawatts and we're hoping that through things like the Rule 21 Working Group we can start coming up with a unified standard for what the inverter might look like for the second hundred megawatts worth of units so that they can accept some sort of control systems.

We are processing all of our sequentially. As they come in, we process them and turn them back around. On the feed-in tariff, we closed the program at 100 megawatts and from what I hear from my management we won't be reopening that real soon. We're waiting for the economy to recover, some of the loads to come up, some of our revenues to look better before we start with the second but I think the average price we were doing was about 14 cents on the feed-in tariff although it varies for time of day and time of year.

And just the last issue, as we try to go higher in the penetration the voltage rise becomes an issue. The European inverters that we've investigated, and I got a chance to talk to Christian at the break, they don't really have as many of the type of inverter it sounds like as the inverter manufacturer is telling us. A matter of fact, the same manufacturer told utility back East that SMUD had a whole bunch of them and I wasn't aware that we had any. It turned out that we didn't have any. That's salesmanship. When people hear about inverters they hear that they provide reactive support, that's not what these inverters are designed to do. If people think in terms of reactive support doing the same thing that a capacitor does for the system. What they actually do is exactly the opposite of reactive support. They will draw vars from the system to lower the line voltage so that they can ship the megawatts on without raising the voltage unacceptably. I've equated that to driving your car with your foot on the gas and the brake at the same time so that you can get the RPMs that you're looking at. The other thing is, and I've made this comment at other meetings, vars are relatively cheap. We buy capacitor banks for a modest amount of money. So the contribution of vars, yeah it can be helpful at times, but what the utility from back east reported that their capacitor banks were turning on and off like maniacs. They were wearing out switches on the devices and they couldn't guarantee any of their customers any of the voltages that are typical to a distribution system when that inverter-based unit was doing its thing.

We're presently participating with the Commission and others in high penetration PV studies. One of the ones with Hawaiian Electric is a great example. They've got a small island that was run on a couple of diesel generators. They had a hotel come in and a matching solar field go in right next to the hotel and then the hotel went out of business. They didn't have the load, it's not about capacity for most of this, we can upgrade wires pretty easily. We can't make load happen where we need load to happen. They had that same problem. And on days when they're maintaining one of the diesel generators they have to turn the greatest part of the solar off because the remaining diesel generator can't swing as the clouds go by, I guess is the story.

We're hoping that by working with those folks we can avoid having those problems here first. They're clearly having them first. Learn from their mistakes or challenges.

Any way, that concludes my remarks.

CHAIRMAN WEISENMILLER: Thank you. You're going next?

MS. SANDERS: Hi. I'm Heather Sanders. I'm with the California Independent System Operator. We're responsible for managing the reliable—am I not on? Shall I restart?

Hi. I'm Heather Sanders. I'm with the California Independent System Operator. We're responsible for the reliable operation of the transmission system. What I thought I would do is talk a little bit about the differences that are required from a system operations perspective on the European grid than we have here. You've heard them mentioned. It's the telemetry, the control aspects and then some of the interconnection standards for power quality, low voltage ride-through, etc. And what that means as far as from a transmission system operator. Just to remind us of the contrast. The German telemetry requirement is 100 kilowatts and above. In the ISO for a resource, distributed or otherwise that's renewable, telemetry is required at one megawatt and above. We also require information from met stations to give us information about wind speed, wind direction, solar irradiance, etc. so we can use that to improve the forecasting and the decrease forecasting error. For all other types of generation, regardless of whether it participates in the market, is 10 megawatts. So that's telemetry.

And I'm really glad that we brought up the difference between telemetry and metering. Telemetry is near real time. I can see what's going on. I get real time information. Our SCADA systems get information from generators on the ISO systems as well as timelines every four seconds. That allows us to understand that state of the system, it also goes into the optimization on the market and what units, what resources get committed to serve what’s coming in real time.

So telemetry is a real time measurement versus metering which is typically thought of after the fact and used for billing. We also use that meter information, that actual, to train our forecasting models. So metering is important in knowing the actual is important to train our forecasting models. But it’s different and those systems were designed for different purposes so talking about the smart meters and the network that was built, it was build to be a settlement in billing system. Now I do believe we can leverage some of that to help support our forecasting models in the future but we need to work that out, how we’re going to do that.

So I just want to talk a little bit about how the ISO plans the system to give some background on why we would have the requirements on telemetry and control. We’re responsible for ensuring that there’s enough supply on the system to meet the demand at every instant; everyone understand that. For a particularly operating day, we operate a day ahead market that seeks to economically commit resources based on the ISO forecasted load. During real time additional energy procurement is done and flexible resources are brought online based on short term forecast and the actual state of the system, which I mentioned. Currently most of the load in California is conforming. So I'm just talking about load forecasting now. I'm not talking about the renewables forecasting on the transmission system, just load forecasting. What confirming means is that in general on aggregate load follows a pattern that can be predicted. And it has a low percentage of error. Currently the error across the ISO system for load forecasting is very low, it's less than two percent day ahead and it's less than one percent an hour ahead. And that's the mean absolute percent error.

We do currently calculate one piece of nonconforming load. That is load that is unpredictable. We don't know when it's going to come and that's for the pumps that are across the system. And they represent a low percentage of that total load but we do forecast that separately.

The reason for focusing on the load forecast in this discussion about distributed generation is that the expectation of the distributed generation that we're talking about in this forum is that it won't be participating in the ISO market. Therefore we won't have visibility into it. So if you're going to put

12,000 megawatts on nonconforming load, it’s going look like a reduction of load to the ISO. That’s going to have significant impact on how we plan and procure resources on the system. So that’s what’s really driving that need for telemetry and visibility is because if you don’t accurately predict that you’re going to have to carry more reserves, more regulation, more load following requirements. That’s going to be a significant cost because we don’t want to compromise reliability. We talked about that in the first panel. To put that generation out there in a local place makes a lot of sense just logically but then one day the sun doesn’t shine.

Over lunch I looked up—we don’t have a lot of solar on the system right now. There’s less than 500 megawatts on the total system that we know about. There’s probably more in the distribution system that we aren’t even aware of.

But from a wind perspective there’s 3,500 megwatts—3,598 megawatts of wind on the system. We achieved an all-time peak of 2,060 at 4:10 in the afternoon one day, which was quite odd. And because of that, because of the forecasting of that, we had so much generation on the system because you aren’t expecting wind to peak at 4:10 in the afternoon so we had prices—I don't know that they were negative at that time but prices were reflecting get off the system, get off the system. So we're re-dispatching the market in the most economic we can to follow what's going on in the system. So it will be important for us as we go forward and integrate this distributed generation to realize that to control these costs we are going to need this telemetry, that visibility.

From a control perspective, the ISO does not have active control over the renewable resources except that they are providing regulation. In order to curtail this as an operations procedure that's done outside of the market if you're in an emergency situation. So that's another thing that really gets concerning. Most recently we had 800 megawatts on wind just drop off the system. And we have to replace all of that. So we're getting to the point where we have significant amounts of generation coming in from resources that we can't control.

So the European systems—one of the things up here is how can learn from the European systems. We have established a renewables desk that focuses on improving forecasting, looking at things coming ahead. It's really difficult in California, I think more so than some of the places in Europe, because we're right

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on the coast here. We have a lot of different typologies than they have there. It's hard for us to see what's coming. We're doing a number of research projects to improve our forecasting all the time. Our renewables desk is being trained to recognize things that could happen like a wind turbine cuts out or in times of high wind, the blades are actually feathered so that you can still get output from the wind without it fully cutting out. We're also working everyday to improve our forecasts. Just so give some data, you saw on the previous presentation on our error in wind forecasting. We have about a 14.75 percent error in wind forecasting day ahead. We have about 6.75 percent error in hour ahead. That's the mean absolute error, that's the MAE.

So it's significantly challenging for us and I bring this up because we have visibility into those units. We have telemetry. To put this amount of distributed generation onto the system without visibility, our forecasting would expect to be significant. So I wanted to bring this up because that's what's driving those European requirements for telemetry and control. I thought that would be important for us to understand that we don't necessarily want to arbitrarily say that it's 100 kilowatts everywhere. As far as the costs go, there's the components that, I believe, Bill spoke about in terms of the developer putting in the measurement devices but that most of the cost is in the communication back, the optimization decision on what to do with that data. There's costs in a number of different places and we need to be very deliberate about how we handle that and recognize without it that it could be fairly significant. I think that's all I wanted to touch on regarding to the European studies so, thank you.

CHAIRMAN WEISENMILLER: A couple of questions. One is what is the exact status of the ISO application at FERC on the ride-through requirements?

MS. SANDERS: Well I have—so we filed on July 2 on interconnection requirements. And the subsequent FERC issued on August 2010. Basically what he's referring to is that there were four points of that – power factor design and operations criteria FERC rejected our proposal there in addition to voltage regulation reactive power control that was also rejected, as well as revisions to generation power management requirements that was also rejected. The one item that was supported was revisitance to frequency in low voltage ride-through requirements.

As far as the status goes now, we're still really waiting to see how that's getting resolved. The direction was to study these individually with each interconnection request so that if these requirements were there they were done at an individual generator level. As far as the rehearing with FERC I'm not sure where that stands specifically but I know that how that's being handled is on an individual basis right now.

CHAIRMAN WEISENMILLER: And similarly, in providing pricing signals to the renewables, where does that stand now?

MS. SANDERS: So we have an initiative going on right now for integrating renewables on a market and product review.

We've just held the initial straw paper to suggest different approaches that may be taken to support reflecting like ramping needs or fast ramping needs because if you think about what's happening on the system now and how we plan for this single largest contingency, I'll tell you that as this increases from a renewable perspective our single largest contingency won't be the loss of one of the nuclear facilities. It will be a loss of the bulk of wind. We need to think about how we're handling that.

The renewable product market review is in its stakeholder process. It’s working through that. There’s a number of initiatives that are out there to address that and get that. One of the components is the price signals that are sent. Right now the lowest that the price can go is negative $30 dollars so you’re not providing a strong enough incentive to the demand side resources or the reduced generation side resources as you are to the supply side. We are going to adjust that floor, if you will. I believe the current thinking is to negative $100 dollars a megawatt or $200, depending on where they land on that. So that should give better negative price signals so that we recognize tons of over generation over supply. So incenting the either demand response or the generation to reduce.

CHAIRMAN WEISENMILLER: Obviously you’re not the only balancing authority in California. So the question in part is what—how are the other balancing authorities responding to these challenges?

MS. SANDERS: SMUD? SMUD how goes it?

[LAUGHTER].

MR. BROWN: That’s not my side of the company.

[LAUGHTER]

MS. SANDERS: Good answer. I’m not sure. I believe it’s got to be more challenging for them because we have a much larger system than they do. They have to be very active of balancing that energy minute-to-minute and second-to-second. He had referred to the fact that they have up on their wall the different generation mixes that they have to balance this stuff because only some of the resources are flexible enough to be able to respond to those frequent changes. We have a larger system. So we have more resources at our disposable to balance this. We also have larger problem as well. I would assume it’s gotta be fairly challenging for them depending on how much native renewable resources are intermittent nonconforming resources they have that they have to forecast for but I don’t know. I would have to have SMUD or LA or someone IID respond to that.

MR. BROWN: They did generously add to the staff of the people that take care of that so I suspect they’re managing somehow.

CHAIRMAN WEISENMILLER: Yeah, it’s just that your story reminded me that I was in the El Paso Natural Gas Pipeline Control Center in about 1986 just as restructuring was start and pipelines basically became common carriers to others to transport gas through the system. And at least, at that point, they had a clipboard that would—they would write down the flows they were anticipating and within a matter of years they were just swamped. Absolutely swamped in terms of the

SCADA system, it was inadequate. Their computer software was just hopeful. It took them years to dig out from under the tidal wave of trying to really revamp their control center to reflect what was going to happen when others started scheduling gas transport in their system. So hopefully you're not in that situation. The company barely survived the challenges at that stage. Gas obviously moves much slower than power so with different time costs, conceptually, it's a much easier challenge but they just got killed on the accounting side.

COMMISSIONER PETERMAN: Just one follow up question, Heather. Assuming telemetry, how suitable are different reserves for dealing with contingencies of the size you mentioned like the 800 megawatt drop in wind?

MS. SANDERS: So the tricky part of that question is that we can't use our contingency reserves to accommodate those drops. We have to re-dispatch the entire system. Our reserves can only happen in, you know, an N minus one contingency scenario. So when all the wind drops off the system we have to do it with the market and the load following the market and the regulation that we have. As far as percentage goes—

COMMISSIONER PETERMAN: Can you just clarify why that is for me?

MS. SANDERS: I'm not sure—it's because of the NERC WECC requirement.

COMMISSIONER PETERMAN: Okay.

MS. SANDERS: And that's also discussed in the paper, it's a different of how you can use your contingency reserves so we need to look at how we're providing our reserves and when you can exercise those reserves because you currently cannot do it at a loss of wind because you're not losing the plant necessarily or the transmission links; the winds died and stopped flowing.

COMMISSIONER PETERMAN: So it may not be technically a limitation on what the reserves can do so much as a technical—a requirement—a regulation requirement now about what we can use them for?

MS. SANDERS: For reliability, yeah, a reliability standard.

COMMISSIONER PETERMAN: Thank you.

MR. LENOX: Yes. I'm Carl Lenox with SunPower. We're a, obviously quite large, solar modular manufacturer as well as a system integrator and product developer. We work globally. I deal with grid integration issues as well as advanced plant control functionality. And so forth I just wanted to provide some comments based on the KEMA report based in part to some colleagues, feedback from my colleagues our of our Frankfurt and our Madrid offices as well.

So I’d just like to say that the KEMA report is pretty helpful in providing additional insight into the situation in Germany and Spain. Just for some context setting, I just want to reiterate that what we’re talking about in Germany is that over 17 gigawatts of installed capacity. But that doesn’t tell the whole story. There was 7,400 megawatts installed just last year. It’s really very concentrated. About 70 percent of it is actually in the southern part of the country. We’re not talking about it being spread out amongst a whole system. We’re actually talking about it being quite concentrated. In addition, as I think we heard, a lot of it is actually in rural radial feeders as opposed to on these networks. These are all important things to keep in mind as we think about that experience.

One of the things that we’re seeing, again, is that we’re seeing greater than 100 percent instantaneous penetration routinely on German distribution systems. I understand that there are differences in the way they do relaying and things like that but that is what they’re dealing with.

I think it’s really important to point out—I saw a breakdown on penetration levels by distribution system operators in Germany—there's 15 DSOs, distribution system operators, in Germany that have PV capacity on their systems that is between two and four times the annual load on those circuits. They have some very significant penetrations on many of those systems.

As interesting as the guidelines that were discussed in the report, I thought it was very interest what was not discussed in the report. And these are issues that often come up or concerns that people have. One of them is anti-islanding. There is an EIA study back in 2002 which found that the risk of islanding, this is a quote, "is virtually zero for low, medium and high penetrations of PV systems." And that's in part of why these high penetrations are being allowed. These are not as concerning as anti-islanding as they typically are here in the U.S. And I think it's important to keep in mind that the 50 percent of line sections screen that we have here for interconnection is intended to avoid situations where PV penetration can match load but I think that's questionable of whether that's a real risk.

I think that also comes into this workload question. If you have a screen that's overly conservative then I think this idea of going to 100 percent of minimum daytime load would help would this.

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If you have screens that are too conservative, that's going to increase workload on the interconnections. These things are actually related.

We talk about another concern people also have around harmonics that often comes up and DC current injection. I saw no indication in this report of any substantial power quality issues.

Interestingly to me, variability, management of variability, short duration of variability was not mentioned in this report. There was no indication of any substantial power quality issues such as flicker or ONM issues related to variability. And, I think, there's a growing body of data on PV variability which is showing the short term changes of output on a single system are far less of an issue than commonly assumed because when you scale you get a tremendous amount geographical diversity that aggregates that short term variability. And that's true even of a footprint of many distribution feeders.

I want to spend a minute talking about communications and controls because that's obviously a major theme of these reports and a major theme of this discussion. I hate to be contrary here but in talking to our folks in Germany very few, if any, PV systems in Germany are capable of communicating the real time output to the grid operator. That capability simply does not exist. I’m not sure why that’s in the report but that’s—real time telemetry is not happening in Germany. However, the German TSLs do have situational awareness and forecasting tools. These are discussed in the KEMA memos. They are quite accurate, about four to five percent in root mean square error on a regional basis. Those are based on modeling the aggregate PV output across the region so they do have telemetry on a handful of small systems. There’s actually private forecasting firms that have this telemetry. They utilize that telemetry from maybe a couple hundred systems to develop regional area forecasts. And those are usually actually to operate the transmission system.

When we talk about remote active power reduction that is again for systems above 100 kilowatts -- it’s been required since about the middle of last year, keeping in mind that everything that was installed before then did not have this capability. So we’re not talking about that much capacity in the scheme of things.

And I also want to point out that the interface that we’re talking about that performs its function only costs a few hundred dollars. It’s based on a pretty low cost scheme and a pretty low cost communications scheme on the upstream side, as far as I can tell. We need to think about the capability of the communications and then the cost of that communications, I'll come back to that in a second.

I also note that my German colleagues tell me that in practice, few German utilities have actually implemented the required communications infrastructure needed to do this curtailment.

The other functionality that's been discussed, such as reactive power, low voltage ride-through, that's only applicable to medium voltage connected systems, about 100 kilowatts. Eighty percent of the systems in Germany are low voltage so we're talking about the 20 percentage of systems that have been installed very recently. So basically very few systems actually have this capability today, of the 17 plus gigawatts. And the reason that they're doing this is to really move forward from that point, I think it's really important to understand that. It's very important to move forward from the point that they're out now to have these functionalities in place but they've managed the system up until now without them.

When we talk about telemetry and things like this the cost that is required of that kind of utility EMS integration in a manner typically done in the U.S.

is very high. It's probably a couple of orders of magnitude beyond what we're talking about in Germany and would be a major barrier. Now if we can—we certainly can do monitoring. We do very high resolution monitoring at reasonable cost. The question is what is the communications infrastructure that's actually being used to get that data or to control the systems. How reliable does it need to be? Do you need to have six nines, three nines, one nine? You're talking about a lot of distributed systems, maybe you can handle having some of those communications not get through to the end. That's something that we really need to think about.

Let me just go back here a little bit and talk about some of these functionalities, particularly around LVRT and the reactive power. These are capabilities that are available in the market today, they're not widely used because we simply can't use them in accordance for smaller systems lower than 10 megawatts. We are starting to see many situations above 10 megawatts who are not in distributed generation kind of situation where we are rolling these out and doing them. The technology is there and it's really more of a codes and standards issue, quite frankly. And we've even done that in Hawaii. We actually installed a system in—that went online in January of 2009, so a couple of years ago, that had extended voltage ride-through ranges, frequency ride-through ranges, telemetry back to the utility. Pretty much everything that we're talking about here. That can be done but it's sort of a question of how you do it and whether those technologies are really commercially available and what the codes and standards are to use them.

That said, I want to bring our attention back to the Black and Veatch Study that was done for Re-DEC back awhile ago. I revisited that study. They had found that you could get more than 17 gigawatts of distributed PV in California with no more than 30 percent penetration on any given feeder after constraining for where there was available rooftop space and so forth. Based on that study we're not necessarily talking about accommodating similar levels of penetration as they currently have in Germany. At the same time, I think, it's pretty clear that we can get above 30 percent penetration. This is penetration now that is peak-on-peak without significant issues in many, many cases. There's always going to be corner cases, there's always going to be—everything's local but I think on the whole, we're going to find that getting above 30 percent peak penetration is not going to be a really major issue.

I think I touched on this but I think streamlined study process and more appropriate screens are really something that we need. The current approach is kind of a barrier to rapidly expanding PV, distributed PV. And I think we all know this but really the major issue here is not so much technical but cost allocation and causation.

I just really want to point out that the benefits of a utility systems upgrades are really critical to many stakeholders. Not just the developer who happens to show up that day and purchases a product that triggers the need for an upgrade. You're going to have customers who may want to grow their load. For instance who may want to install or buy a plug-in electric vehicle, a utility who may have a whole bunch of electromechanically relays that they're then going to replace and enjoy the benefits of having new equipment for many, many years to come, not to mention the next developer who many come along the line and install the next step after that project. And really society as a whole by integrating clean energy into the system. There's many, many stakeholders who benefit from these upgrades.

There's a really interesting institution in Germany it's called, excuse me I'm totally going to mangle this, but it’s called the Clearingstelle EEG and what it is is an arbitration body that was created as part of the renewables procurement laws that allows developers and utilities to quickly and cost effectively settle disputes in arbitration when they—specifically around PV systems settings and integration. It’s a neutral body that allows these issues to be worked out in an efficient way. That’s not something that we really have here in the U.S.

We really need to consider the cost requiring advanced PV functionality versus the cost of the utility system upgrades. So ratcheting up requirements and requiring that inverters do this, that or the other thing. It may not necessarily be the least cost solution, I think that we need to understand whether that upgrades on the systems side that allow you to accommodate much higher penetration versus having it be on the server technology side, on the PV side of the system, need to figure out what’s the most cost effective there essentially.

And the other thing that I just want to point out is that we often talk about how PV can be a problem for the grid but really with this advanced functionalities, I’m very convinced that PV can really be an absolute asset to the grid. You’re talking about putting very sophisticated power electronics and embedding it ubiquitously through the power system. The opportunities there are tremendous. To really unleash that we need to start thinking about mechanisms to compensate system owners for these grid services, essentially insularly services; we've only really thought about that in the past of the transmission level but really we're talking about insularly services all the way down the distribution. I'll just leave you with that thought and thank you for giving me the opportunity.

CHAIRMAN WEISENMILLER: Thanks. A couple of questions. One of them is who does the codes and standards in this area and what's the current status?

MR. LENOX: SO there's really two interlocking— well, there's several pieces but the two main interlocking issues are between IEEE 1547 which sort of talks about how distributed generation needs to interface with the utility system and the current incarnation of that was written to assume very low penetrations of DG. Those requirements have then sort of gotten mirrored into UL 1741 which is essentially a testing standard. If you want to get a UL listing on an inverter you have to be able to meet that standard. In turn, if you want to be compliant with the national electric code for behind the meter system, you have to have a UL listed inverter. Where this all comes into play, you want to pull an electrical permit from the building department you have to have a UL listing. A UL listing precludes you from actually doing many of the things the utilities would like you to do in terms of the functionality.

So there's a lot of work going on to add a high penetration DG section, essentially, in 1547 which will allow some of this functionality which will then eventually in turn roll through the UL standards and then, hopefully, into the NAC. This is why we've been able to do this for projects that are not—don't have to have UL listed equipment. The utility has some flexibility in interpreting the IEEE standards. It's essentially voluntary so we have some more wriggle room and we can actually rule out these functionalities.

CHAIRMAN WEISENMILLER: Next question, in just a nutshell, compare your experience interconnecting in Germany to interconnecting here.

MR. LENOX: Actually, I don't have any direct experience with interconnecting in Europe but from what I understand it's reasonably straightforward, at least in Germany.

CHAIRMAN WEISENMILLER: Okay. We'll go on to the last speaker then. Thank you.

MR. LENOX: Thank you.

MR. KORINEK: Commissioner Weisenmiller, I'm Dave Korinek with KEMA. I apologize, Christian Hewicker had to leave for his flight to return to Europe so I'll be wrapping up comments on the panel for KEMA.

One thing that Christian wanted me to clarify was in terms of the curtailment option, we've talked quite a bit about that today and that option is available in both Germany and Spain. But it is the option of last resort under the law and all other measures, including market measures, need to be exhausted before the renewable curtailment measure can be evoked. They're very wary of pulling that trigger prematurely. They would pull that trigger as a last resort as opposed to curtailing load, for example, in order to retain balance in the system so there is a real consciousness there that all other measures need to take place first.

One thing that Christian mentioned that I don't know if it was clear but that I wanted to emphasize the approach in Spain is also radically different from Germany in terms of the compulsory nature of the interconnection. Under German law, the DSOs must connect. There is no way for them to deny connection.

Under Spanish law, basically, the DSOs have set an arbitrary cap on DG penetration of 50 percent of the circuit peak demand or the distribution substation peak demand or the area peak demand. In fact, where back feed conditions are very common in Germany with the must connect paradigm, in Spain they're much less of a problem.

I appreciate all the comments, on behalf of KEMA, I appreciate all the comments that were shared around the table by fellow panelists. We're looking forward to seeing all of the written comments as this is still a work in progress at this point, a final report will be coming at a later date, and so we're looking forward to receiving all of these comments in written form so that we can properly reflect them in the final report.

Just to capture an analogy that was on one of Christian's slides, we looked at the cross of the coming tier of renewables in Germany and how expensive the German utilities have calculated that's going to be as compared to what they've been able to connect so far, which has been relatively low hanging fruit. Taking a step back and comparing notes on what we've heard today and what we've seen, clearly there's going to be some low hanging fruit in California also but our impression is because of the differences in the distribution system design that there's probably significant less low hanging fruit available and that it's going to take more capital investment to get those significant increases in DG deployment. So those are our comments today.

CHAIRMAN WEISENMILLER: Thank you. I just had one follow up which Christian referred to in passing. What happened in Germany that led to the much enhanced requirements on the DG side in terms of power quality and all and visibility?

MR. KORINEK: I suspect it's simply because of the magnitude of the deployment that they've seen to date as you look at the percentage of their total system demand and their total system resources. It's become such a significant percentage that the aggregate effects of the on their system is cumulative, of course, so they have to manage it more tightly.

CHAIRMAN WEISENMILLER: Yeah. My impression is that they may have had an incident too last year but that's again something that you can follow up in writing. Thanks.

MS. KOROSEC: All right. We thank our panel very much. This is a very good discussion and we'll shift gears now and talk about the Energy Commission's Staff Report on Renewables on State Properties.

Heather?

MR. TUTT: As you know—you may know, SMUD is no longer a balancing authority. There's now a balancing authority of Northern California. And I'd be happy to ask the people that are responsible there if they are—what they have been doing about similar issues that they have raised and get back to you on that questions.

CHAIRMAN WEISENMILLER: That'd be great. Thank you.

MS. RAITT: Are we ready for the next discussion? Great. Again, I'm Heather Raitt. Here to talk about now the—we completed a staff report looking at developing renewable energy on state properties for this workshop and there are hardcopies at the table that many of you may have already picked up. As far as I know there's still some copies out there.

So the report actually looks at developing a goal for developing renewables on state property and an inventory of opportunities and we also looked at the state's--actions agencies have taken to date to install renewables and go over barriers and potential solutions and next steps.

So the report actually focuses on DG but it's not exclusively DG. It also includes the larger scale and utility scale renewables so we're considering this report as actually helping us more toward the 20,000 megawatt goal.

Initially we looked to see what the benefits might be for developing renewables on state property. We see potential for reducing energy costs, for creating new revenue streams by leasing the rights of way on vacant lots to developers, some cost savings by eliminating maintenance obligations for lands leased to developers and we hope to have—be a leader in spurring development. The aim is to build off of existing programs and to not increase net costs to the state.

It's a joint effort. There's eight agencies that have signed a memorandum of agreement with the Energy Commission as well as the Departments of General Services, Corrections and Rehabilitation, Transportation, Water Resources, Fish and Game and the State Lands Commission, and the University of California. It's open for others to join and in fact the State Lands Commission and the University of California joined since it was first signed in December, I believe.

To begin, we have put forward a goal of 2,500 megawatts by 2020. This is developed in consideration of the 33 percent mandate as well as the 20,000 megawatt

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goal as I mentioned. It builds off of the inventory that we conducted of the possibilities of development on state property and we're cognizant of the loading order. We're recommending that we first develop on state buildings that have invested in—have made investments in energy efficiency.

It builds off of the inventory in that for state buildings we estimate potential for between 14 and 26 megawatts of development. We think of that as the low hanging fruit. Next we developed an estimate of potentially wholesale distributed generation and we saw that as between 54 and 195 megawatts and finally land lease for wholesale generation. This is where we get into the potentially utility scale. This is really a very gross estimate of technical potential so it's in the range of 14,000 to 26,000 megawatts.

Our goal is—so we're suggesting that perhaps 10-20 percent of that technical potential could be realized and that's how we get to the 2,500 megawatts.

We have several activities that are already underway. The Department of General Services has contracts to install 12.25 megawatts of PV. We've heard a little bit about Caltrans working on getting PV along the highway system. Department of Water Resources is working on a demonstration program for the California

Aqueduct and installations along the pumping plants. They've put out an RFP for a wind demonstration. CAL FIRE is looking at using wood waste for producing electricity. Department of Corrections has recently—well they have one megawatt of ground mounted PV and have vendor contracts to expend that to 23 megawatts. State Lands Commission manage thousands of acres of school lands that are a revenue source for the State Teachers Retirement Fund and this is where there's a lot of property that has a potential for development of the larger scale renewables. And then University of California. They have committed to installing 10 megawatts onsite by 2014 and they already have over six megawatts of PV and they expect to have six megawatts of biogas by the end of the year.

Then we talked about the variance of solutions and I won't get into these in too much depth since we've been talking about them already today. For economics, the high upfront costs and transaction costs and then specific to for the state expense we are running into some issues around contracting as well. For integration we talked about that with the intermittency. We'll hear more about that this afternoon with our D&D discussion. Interconnection we talked about that with the challenge of a interconnection requests. And then permitting we

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haven’t talked as much as about that today. For the state agencies, they have the authority to conduct their own permitting for actions on state property but it needs to comply with the California Environmental Equality Act and be consistent with any local regulations.

We definitely see permitting as a major challenge for the larger scale projects and our inventory doesn’t do any screening, at this point, for the really large scale projects so that would be a future step.

We first looked at the potential for buildings in the load centers which we divided up into seven load centers. We excluded buildings that were in sensitive lands or that had existing projects. We collected monthly and annual meter data to help us evaluate the potential. We also looked at the square footage of the rooftop and the parking lot spaces and were actually able to net our obstructions in North facing areas of roofs. We then estimated the total PV capacity to be about 16.2 megawatts. I had meant to actually say this upfront that much of this capacity that we’re talking about is in terms of PV but we actually happen to have a broader mix of technologies going forward.

Then the next category that we looked at was state property with potential for wholesale. We looked at Department of Corrections' property and Department of Mental Health Facilities. For Corrections they were able to do a little bit more advanced analysis excluding areas that had insufficient interconnection opportunities for topography or had environmental sensitivity. Having applied that screen, we see potential for about 50-200 megawatts of DG with wholesale potential.

Finally, the category of looking at areas that really were for wholesale. We looked at available space around aqueducts, siphons, pumping plants, excess lands, other state lands and highway intersections. We kind of looked at parcels, we divided them up into groups of if they were 200 acres or smaller. We assumed that those could support a wholesale regeneration and if it was 200 acres of above then it would be a utility scale project.

Based on this very rough technical estimate, we came up with about 14,000-26,000 megawatts PV potential. We also looked at areas that had good wind resource availability. There's about 100 parcels and that those have the potential of about 1,900 megawatts.

As I had mentioned, there's much more work needed to determine the suitability of developing these parcels and that is something that we would like to do going forward.

So next steps, we're interested in working with more agencies to join the MOU. We want to continue to refine the inventory. Working with the Department of General Services to develop a request for proposals for renewables on state buildings. We are planning to do a screening environmental analysis for the properties area to get a better sense of what areas would be best suited for development. And then today we're hoping to get more comments on the report and feed the results into the renewable strategic plan portion of the Integrated Energy Policy Report. That's what I had. Thank you.

CHAIRMAN WEISENMILLER: Thanks, Heather.

MS. KOROSEC: All right. Next we'll hear from KEMA about what from the European experience relates to renewables on government property topic. So Karin Corfee.

MS. CORFEE: Hi. My name is Karin Corfee, I'm with KEMA. I apologize but Christian had to leave and catch a flight so I'm pinch-hitting for him today.

So KEMA actually did three memos in preparation for a consultant report on the EU experience with DG. This presentation is real brief. I'm just kinda going to skip to the key conclusions but this is related to Memo #3 which is what the experience is with

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renewables on public property.

We investigated key questions, which I'm going to summarize at the end so I'm going to skip over this, and I think it's really important to touch upon what's really driving the market of renewables in Europe and without focusing too much on this there is the EU's 20-20-20 goals and so 20 percent reduction in greenhouse gases, 20 percent reduction in energy consumption and then 20 percent reduction in—and 20 percent share of renewable energies by 2020. And these are binding targets.

And I asked today what does that mean binding? What happens if they don't meet it? And it's very squishy binding targets. So that's just an FYI in case you guys are curious.

But one of the key things is this EU Directive that came out in 2009 and so there's some key things that have really kind of set the groundwork in Germany for renewable projects along highways so that's a key thing that we found in our report.

This just summarizes where we have fits and what some of the rules are. I'm going to skip over that.

This EU 2009 Directive, I'm skipping all the way down to the bottom bullet point here, really focuses in on zero energy housing but also set the groundwork, really clarified and explicitly called out renewables along highways.

For the most part, public authorities have really played the role of just facilitating renewables within their communities. They're not really taking an active ownership share. In Spain, there's a lot of pilot programs but in Germany where we're seeing things really take off now are these PV installations along the interstate highways.

And then this is kind of interesting. In Germany they actually use CO_2 emission allowances to fund a schools program where their target is to put PV installations on 400 schools. Interesting to think about for the State of California.

So we have some details on the installations along the interstate highways, I am going to skip over it but I do encourage you to, if you have questions, please file written comments and we can clarify in our consultant report.

There's some photographs of installations along highways and along noise abatement walls. So the 2009 EU Directive actually in Germany the new renewable feed-in tariff laws specifically called out noise abatement walls as well as highways. So the lower picture is actually a noise abatement wall and the upper pictures are examples of highway installations.

Summary of observations. One of the key questions was whether European countries placed solar DG on government buildings and is it a common practice or a new practice. As I said earlier, governments are facilitating but they're not taking an active ownership role. That is starting to change a little bit. We're starting to see more public private partnerships but in general the publically owned projects on public property is really taken up by private investors.

We have seen some limited expansion of DG on state property in Europe. And it's likely to occur because of this recent 2009 EU Directive specifically focused on the municipality's responsibility to promote and to serve as a good example so they actually are now specifically required to make available rooftops of public buildings. We're expecting to see quite a lot of activity from 2012 onward.

There's also economic drivers. The economic drivers really come from land sales, leasing fees and taxes. The municipalities do receive income from all of these sources.

Lastly, I think that there's tremendous public pressure, primarily to reach the European climate reduction goals or greenhouse gas reduction goals. We do see—we see a concentration of solar projects and DG projects in certain areas and those tend to be the areas where you see very active public support for renewables in DG.

So another question is do renewable DG projects on government remote properties go through a normal or expedited permitting process? And there's really no difference. So there's no different between projects that are publicly owned or privately owned or projects that are on public property versus private property. We found no instances of expedited permitting processes.

It is important to note that in order to get feed-in tariff that the local development plans do have to be adjusted to allow renewables on public property.

There is a more lengthy and complex, typically, approval process for projects on public property.

So how do European programs for renewables address issues such as safety and some of the other environmental issues? In general what we're seeing is that there's not really special provisions in Austria, Spain or Switzerland but in Germany they've explicitly extended the feed-in tariffs for solar PV installations along the highways. As a result of that, there's a federal law on highways that basically—it's a federal authority that has oversight on projects along the highways. And then there's also been municipalities and state authorities that also have oversight.

In terms of how projects are financed, we have, for the most part, most of the projects are financed by private company investors and local authorities and these are usually utilities and private investors. And, as I said, sometimes you see the municipalities invest but it's very, very—not very common. And then for fully dedicated municipal projects, financing typically comes from municipal budgets, local banks and other sources such as subsidized regional development and energy efficiency funds.

The private partnerships typically have access to investment credits and foreign capital and so even if their private or public partnerships, by virtue of them being a private entity and a partner, they do have access to the foreign investment credits.

Are there special or higher incentives or tax credits?   In general, installations on public properties are subject to the same rules and financial support. They really don't make an exception for public property.

What are the ownership and revenue structures? There's investor led projects and these are, as I said, the most common. There's public, private partnerships which are now starting to emerge as being more common but certainly way less common than the investor led projects.

And then we have a number of other different revenue structures, cooperative projects, energy contracting, public ownership and operational responsibility and ownership by a municipality administration.

And I think that's it. Thank you. Any questions?

CHAIRMAN WEISENMILLER: Thank you. More observations. I was going to note that in the first round of administration, looking at his energy policy at that point, one of the three elements was basically using public facilities in a leadership role in dealing with energy efficiencies and renewables. Obviously, this program has a lot of resonance now in the new ground administration.

I think in terms of one of the things—but obviously with the budget realities we have to do a lot of this work with public private partnerships. But I think certainly the solar highways program, the German example of theirs interest I would note that in the Governor’s campaign document he was specifically calling for solar highways in California. I would also note that certainly PG&E’s experience with—back in the days of their bankruptcy was solar in schools which was the most popular thing PG&E had ever done in the 2000 ish period in terms of focus groups, polling and everything else that had remarkable public support. So again, I think, in terms of encouraging all the utilities to look at extending and expanding those types of programs.

MS. CORFEE: And I also think that the carbon allowances was a pretty interesting way of financing it. The other thing that—one of our key questions that I kind of skipped over, Commissioner Weisenmiller and Commissioner Peterman, is the waterways. I know in California we have a lot of irrigation waterways and there’s really no similarity to the market in Germany or Spain or Austria and Switzerland. So for waterways in Europe they’re talking about beautiful rivers and it’s different than irrigation in remote areas so what we found were very few, if any, examples of DG projects along waterways and what we found was that there was a lot of public pressure against projects along water ways for obvious reasons. It was hard to develop the parallel there for waterways.

CHAIRMAN WEISENMILLER: I did notice that you also mentioned the railroads were obviously a difference between the role of the railroads here versus there at least in some attempt to use those waterways.

MS. CORFEE: Yeah. The feed-in tariffs in Germany specifically called out Germany railways but we've seen no example of projects along railways.

CHAIRMAN WEISENMILLER: And I guess the other thing is that interest adversely, we haven't gotten very far in solar but the noise abatement walls. Are you trying to do that along the freeways?

MS. CORFEE: What's really interesting about noise abatement walls is that they're looking at it as a way to fund noise abatement walls. So the solar component of the project can actually provide enough revenue to fund the noise abatement walls. And often time that's where you see the instances of public private partnerships where the public entity is funding the noise abatement and the private entity is funding the solar and then there's a subsidy for the two.

COMMISSIONER PETERMAN: Do public buildings face a different rate structure than commercial or residential buildings in Europe?

MS. CORFEE: No.

COMMISSIONER PETERMAN: Thanks.

MS. CORFEE: So there’s municipal utilities and sometimes they’re publicly owned but it’s a private corporation set up to run those municipal utilities so it’s spate

CHAIRMAN WEISENMILLER: Thanks.

MS. KOROSEC: Next, we’ll hear from Julia Donoho from Sonoma County.

MS. DONOHO: My name is Julia Donoho and I’m from the County of Sonoma. I work in the Architecture Division of General Services so I build things rather than generally providing view on energy although in this case I have built a fuel cell power plant and that’s why I’m here today.

A little background first about Sonoma County since I’m here to talk about how do you put facilities on state properties or government properties. Our course has been a long one. In 2002, we had a consultant evaluates our facilities for greenhouse gas emissions and that consultant identified three aspects to our impact on greenhouse gas and that was commute, buildings and fleet. And the consultant identified some projects that we could do to reduce our greenhouse gas footprint.

Out of that we did a landfill gas project and that's capturing and turning into power the landfill gases. We set a course for demonstrating policy and leadership in energy and environmental goals. What that turned into then was a community protection plan for the County of Sonoma in 2006. That, again, identified commute buildings and fleet as our main source of greenhouse gas and energy impact. That plan came up with a plan for us to add hybrids to our fleet, electric vehicles and hybrids I should say and to do a variety of energy efficiency measures and to add co-gen and in that case it suggested distributed generation of 1.2 megawatts for our load.

It recommended hiring an energy services company which we followed through with. We hired—we did an RFP, it took about a year to hire our energy services company. We did an inventory grade audit that took about another year. So by 2008, we were ready to go with a comprehensive energy project. At the conclusion of the Climate Protection Action Plan for Sonoma County also the Board of Supervisors of our county made a resolution to go beyond Assembly Bill 32 and greenhouse gas reductions with targets of 20 percent below 2000 levels by 2010 and 25 percent by 1990 levels of 2015, which is coming pretty quickly. We have a challenge.

I want to thank Heather for putting this together today. This is very inspiring that ya'll are doing this and the Governor of 20,000 megawatts by 2020. Binding or not, the County of Sonoma will always strive to meet and exceed any targets you give us.

So our energy services company did an inventory grade audit and came up with about 170-180 measures of efficiency and generation that we could do. We limited those by payback and other goals and came up with a list of 101 measures that seemed feasible of which we're trying to pursue each.

And then that was further limited by three primary goals. One was cost neutrality, second was—well, first was greenhouse gas reductions, second was positive financial impact and third was infrastructure renewal. So we came up with a package of 38 measures in 24 buildings that include energy efficiency lighting, water valves, controls on each HVAC, new HVAC, new boilers and a 1.4 fuel cell power plant. All together in Sonoma County we now have our five to six megawatt landfill methane, we have 820 kilowatts of solar for our 1.6 million square of buildings.

I would like to talk about rooftop but I'm going to reserve that for a minute.

We have 1.4 megawatt fuel cell. Currently it's utility supplied natural gas not green natural gas.

We have a PACE program, Sonoma County Energy Independence Program Property assessed clean energy where we've issued—approved $53 million of loans for distributed generation on residential and commercial facilities. We have another one megawatt of biogas of compost in development at our landfill and we have an aggressive EB program. Also the Sonoma County Water Agency has two megawatts of solar at three different installations, 2.64 megawatts of hydropower. We have a chicken byproduct biogas facility of 5.6 megawatts in development. The water agency has a goal of carbon free water by 2015. They're also looking at geothermal and they have 22.4 megawatts of renewable energy in development including wind turbine, wave energy they've looked at at the coast and a community choice of aggregation of feasibility study is in progress.

Also, we're eager to implement some Bloom Boxes so we're trying everything that we can and we think that you can too.

For our fuel cell, 1.4 megawatts. We chose a combined heat and power plant because we placed it at our central mechanical plant where our boilers and chillers are. We had created the central mechanical plant years ago to serve our whole campus. Our load characteristics for electrical energy are 800-900 kilowatts nighttime energy winter kind of characteristics or not continuously that much. And going up as high as two-and-a-half megawatts on a summer day. Our current agreement with PG&E is to have uncompensated export because we kind of have a bigger fuel cell than our total minimum load and that was a difficult thing to negotiate but we've very grateful for PG&E for that. The interconnection was a little bit difficult because it had to come through at the same time that they were dealing with San Bruno and the staff was quite busy but they made it happen. They were terrify to work with.

We have a net generation output meter on our fuel cell but we do not have one on our 12KV system so we can only at present see when we're generating zero and when we exceed zero, I mean when we're not exporting zero and when we exceed zero—I mean when we're not exporting zero and when we exceed exporting—when we start exporting we see that but we don't see our load characteristics between the 800-900 and the 1.4. We do have meters on all of our buildings but we don't have them digitized. They're not smart meters. They could be smarter. The cost to make each meter smarter is about $25,000 a building that wasn't included in our energy project but if you have a campus that might be something that you need to look at.

The reason that we ended up with 1.4 megawatts was because that was what was available of the manufacturer that we had already entered into negotiations with had a large contract to provide 50 1.4 megawatts to Korea at the same time that they were going to be building ours. Ours is the first article of the 1.4 megawatts here in California and so it’s the biggest one in place.

We would be really happy to get the feed-in tariff in place even for our currently non-renewable fuel cell our demand charges are quite high on days when fuel cell takes down for some maintenance. It’s happened once or twice. It could be $36,000 charge for the month just because we go out for even a couple of hours during the peak time.

Comments on the report. I thought it was a great report, well done. For the distributed generation target that the Governor has set of 20,000 megawatts, It didn't really say whether there were partnership potentials. So if you had a fuel cell in an urban area and you offset that with a biomass or biogas or something in another area that might count within that target, that would be something worth looking at. I would recommend that the state portfolio divest in various technologies in load demand response. Load demand wasn’t well spelled out in the report, it could be clarified if the 12,000 megawatts is primarily meant to be a 9-5 thing or if it’s a 24/7 desire to have that as a backbone for the system or if it’s meant to help during peak times and how that interfaces with how the utilities are providing peak loads. I’m not an expert in that area, I’m more of an expert in buildings. I’d like for the report to say surface area instead of rooftop when it refers to buildings, certainly there’s a lot of skyscrapers and some of the highest load centers that have curtain wall possibilities in which case rooftops are not a great area compared to the floor area and the demand of the building. Also, it’s my experience as an architect having done a lot of different kinds of energy projects that PV on roof doesn’t really run a whole building, it doesn’t really successfully run pumps and motors and lights and electric requirements all together. It’s never a complete system for a building so you need to have multiple ways in high load centers for providing things. Also rooftops are frowned upon in our county because of facilities maintenance issues. Rooftops, speaking as an architect, are three percent of construction costs. I’m also an attorney, rooftops are 50 percent of lawsuits in the construction industry. The damage from leaking roofs, mold and deterioration of buildings is huge. Adding solar on top of rooftops with different life expectancies is problematic. Maintenance issues are big when you put solar on rooftops. Even removing barriers. Solar is great for daytime load but maintenance, I look at Alameda County which is one of our models we liked what they've done there, rooftop though is a huge maintenance issue on top of that rooftop solar. The fuel cell is just one little box in the back of the lot. You can imagine the difference in terms of facility difference. Also, a building's useful life is 50-100 years. The roof's useful life is maybe 20 and then it has to be replaced. So we are on a continual program of replacing roofs and that may not be the same as the solar systems useful life, especially if you're trying to put them all on a bunch of roofs at the same time. At least you'd want to coordinate that of when you're putting a new roof on.

Another reason why I'd like to see the report reference surface of buildings rather than rooftops only, not just that curtain walls are available, but also the International Green Construction Code is coming out in 2012 that will go beyond what CALGreen is now doing for building codes and it will require higher efficiencies and effect the design of buildings in their form and envelope the shape of the buildings and all of those things and that is an area of opportunity for state owned facilities, all facilities really, it’s a very forward looking code and won’t be as impactful here in California because we have CALGreen as it will in the rest of the country. Let’s take advantage of what it’s offering or going to require and look at that a little bit.

Also, what I’d like to say is that solar as shown in the report is five to nine acres per megawatt so 12,000 megawatts looks to me to be about60-108,000 acres. From my estimation what you’re looking to do is to provide a solar farm the size of the City of Sacramento and that’s a huge environmental impact, even if you’ve spread it around the State of California. Fuel cells take up 1/20 of an acre, I’m not here to say fuel cells are better I’m just saying they’re something to look at with this.   So that’s about 600 acres to provide 12,000 megawatts over one square mile. And there’s no CEQA review because CARB has certified fuel cells as ultra clean.

Finally as an architect I want to put on my architect hat. Are there any other architects in the room? Okay. So I have the floor and I’m going to take advantage of that. I’m a member of the AIA, American Institute of Architects, and Regional Urban Design Director for the AIA Redwood Empire and also the Vice President this year.

From a planning point of view, I’d like to see your report add some other partners for your effort. One is agriculture. The Agriculture Commission seems missing here with the irrigation water and composting and biogas and all those sorts of things. I think that’s a real opportunity for you. Also, what you’re looking at is that you’re basically farming the Earth’s natural resources for energy – solar, wind, hydro, fossil fuels. Whatever you’re using, you’re basically farming it similar to growing food. Similar to if you can create some sustainability between all the growing of food we do here in California and the creation of that energy to create a net zero that would be an excellent thing to be looking at not that that effects the state buildings as much but those are state facilities.

Also, another potential partner is the Strategic Growth Counsel. They’re doing the planning for the high-speed train and if Caltrans doesn’t really want solar along the highways then maybe get it into the high-speed train corridor and get your bang for the buck at the same time as they’re building because that might be easier than retrofitting.

Finally, I’d like to also—also, if you do something along the corridor you have that great opportunity to bring the biogas and the biomass to the side and have fuel cells along there pumping energy into a grid that’s distributing back to the urban centers. But there will be more urban centers along the Central Valley if the Strategic Growth Counsel’s report come true of what happens once you put that in place.

I’m looking at the train because we’re putting a train in in Sonoma so it’s a big deal how you change your urban infrastructure and how you change redevelopment, SB 375, all those are part of the energy equation. At the same time that we’re trying to catch up, we need to look forward and get ahead of the game. You have 10 years forward to look. What’s this going to look like in 2020. What will you have accomplished now that we’ve been through this process, it’s been nine years since 2002 when we did our first report and we have now, we can check that we did this, this, this and this. And this is where we’re still going so I would urge you to do the same. Thank you.

CHAIRMAN WEISENMILLER: Great. Thanks. A couple of questions. One of them is as we were marching forward at least—anyways, the question in part going forward is trying to figure out a way to do partnerships with the local governments in this area to try to build off of expertise. Obviously, you have a lot of expertise in this area that we could benefit from along with I'm sure other local governments. I think that may be, I think we mentioned earlier, that we're trying to do a working conference later in the summer and again this could be a topic there. The other thing that's interesting to look at is when you look at our federal partners, particularly looking at military installation in California, I'm going to cite particularity the Navy-Marines under the ex-Chair of the Commission Jackie Pfannenstiel. Who had very aggressive policies on reducing their energy use by energy efficiency and also by using renewables in bases in California. That again sets a good leadership role for all of our.

I guess the last thing is one of the things that the State Treasurer, the Governor's Office and I have been working on is trying to deal with commercial retrofit and one of the things that we've been encouraging the utilities to expand the on-bill financing programs. I don't know if that would be of assistance or not in your operation.

MS. DONOHO: For on-bill financing we are pursuing every kind of financing. And yes, we've looked at that for certain projects that have under the 16 year payback, is that the one with the—we have ARRA funds, on-bill financing, all sorts of things going on. I'm not the right person to talk to that matter though. In terms of partnerships, we're also trying to create lots of partnerships and we'd be happy to help in that area.

CHAIRMAN WEISENMILLER: That's good. The Governor and the Treasurer have a high priority in really trying to move along commercial retrofit. And so are then interested in learning more about the financing side such as on-bill or other ways to do that but certainly trying to move forward.

MS. DONOHO: The interesting thing in the International Green Construction Code which is not in the CALGreen code that we've just adopted here in California is that it will require commercial retrofit projects to meet energy targets and sustainability targets. Only the first TI of a core-and-shell project would have to meet any of those targets in the CALGreen but in IGCC, I think anything over 10,000 square feet or 50 for sure, will have to, even if it's a retrofit or a remodel, will have to start meeting all the same targets as new construction. Over, say, 20 years it will pretty much hit all facilities.

CHAIRMAN WEISENMILLER: Okay. Thanks.

COMMISSIONER PETERMAN: So how where your fuel cell and energy efficiency projects financed?

MS. DONOHO: We financed our projects through incentives, grants and financing through Bank of America 421710 financing. We had a slightly bigger project planned but we cut it back that first fall to make sure it would be cost neutral the first year but then net zero impact to the county budget which was kind of difficult because we took out some projects that we really wanted to do, some infrastructural renewal and so forth. But we wanted to make sure that it files smoothly and does pay back in a short time. I think our estimate though was over the 25 year period, we'd pay back $40 million for a $22 million project.

CHAIRMAN WEISENMILLER: Andrew, go ahead.

MR. MCALISTER: I just wanted to make a point of clarification. This is Andrew McAlister from the California Center for Sustainable Energy. Sonoma County is actually doing an on-bill finance program through the water utility. And SDG&E also has a fairly aggressive, I think, well done on-bill finance program in their utility territory. Very little discussion has been done on the financing—at this point it hasn't been brought up much today. Financing is really totally key for getting the smaller end of the DG spectrum done and that's really a big gap in the marketplace right now. We have PACE, we don't have it right now but we will have commercial PACE in a number of jurisdictions in the next year or so. I would suggest, I really just wanted to clarify what I perceived as Commissioner Weisenmiller's question, but I would suggest that commercial PACE could be a very good strategy in incorporating it in this planning effort in the near term and not wait until residential PACE gets figured out because commercial PACE is basically ready to go. Thank you.

COMMISSIONER PETERMAN: Thank you, Andrew.

MS. KOROSEC: All right. Thank you, Ms. Donoho. Now we're going to shift gears once again and go to our last panel of the day on research development and demonstration efforts and that's going to be led by Linda Spiegel from the Energy Commission Staff.

MS. SPIEGEL: Hi. Good afternoon. In the interest of time, I'm going to skip through some of these slides and go through some of these quicker. I'm Linda Spiegel and I'm with the Research Development and Demonstration Division of the Energy Commission and in particular I'm with the Energy Generation Research Office. I'd like to acknowledge my college shown here who put together this presentation.

So what we're going to do here, I'm thanking the panel for taking the initiative for going ahead to sit down, I'm going to provide a very brief overview of PIER's efforts in distributed generation. Then we're going to have a panel of five people talk about some select projects that we've sponsored. And then in the end if there's still some energy in the room, we'd like to seek input from the attendees on the direction that you think research should go in this area and if you don't have a lot of energy by then, then we would still appreciate it if you provided it in writing.

Just in case you don't know, PIER is Public Interest Energy Research. We get about $86.5 million a year for research to look at—to conduct research on science and technology in areas shown here, energy efficiency, renewable transmission distribution, climate, environment and transportation. I'm not going to talk about this because you've heard about it all day but I just want to mention that all of our research initiatives at PIER are driven by policy and are tied to policy. And now we have also the Governor's Clean Energy Jobs. You've heard about the challenges already today. We've listed most of them again here, these are just some of them. PIER often lists its challenges as their opportunity for research. In the Renewable

Generation Office itself, this shows some of the goals of that program. In particular, they demonstrate integrating renewable energy at three levels – utility, community and buildings. They like to address the integration barriers and provide reliable access. They look at projects to increase storage and improve forecasting. All of which you've heard a little bit about earlier today.

This is an example of some of the work we do in our community scale projects that's called RESCO, Renewable Energy Secure Communities. We are currently funding 11 projects in this area and just to summarize the purpose of these projects, they have to demonstrate three technologies that are indigenous or that are locally available to them with the goal of meeting 100 percent of that particular community's energy needs.

Again, we have 11 different projects. You'll hear from some today so I won't go into a lot of detail. One example is the UC Davis West Village. The purpose of this is to provide all of the energy needs for about 3,000 families that include homes, education and recreation centers and retail uses. And you can see the plan technologies here. In addition to energy efficiency and demand response, they're using this array of technology so it's a pretty interest project.

Another one is our Santa Rita jail. In this particular instance, we are demonstrating integrating smart grid.

Other research involving distributed generation, involved digesters. We are looking at taking organic waste and reducing the waste stream while producing electricity and other products such as soil amendments. We're looking at ways to reduce construction operation and upfront costs of solar technologies in the environmental area. We've heard a lot about the problems of permitting today, we're sponsoring a lot of research on that in our environmental group as well as we're looking at the potential of photovoltaic on landfills, closed landfills. In California, there's something like 225 closed landfills. And there's an estimated potential of about 7,000 megawatts of electricity from those so we're looking at the feasibility for those. In addition, we're putting together a roadmap to help understand the co-benefits of air quality and using alternative fuels and renewables so we have a lot of things going on in this area.

The purpose today is to ask the panel to discuss these questions, I won't go over each one because it's on the agenda so in the interest of time, but in addition we'd like to hear from people outside of the panel, what they would like to see the R&D role take in distributed generation. Where usually the biggest barriers are where we can help—we can try to help solve those barriers.

So again, if you have energy, we'd like to hear it at the end of this otherwise please provide it in writing. So with that, I would like to introduce our panel members and have them start right away. They can come up here in order that they're shown. Jan Kleissl of the University of San Diego will start.

MR. KLEISSL: Thank you. Firstly, I'd like to thank the sponsors for our research, the DOE high PV penetration program and actually will have, by chance, a workshop in Sacramento on June 13th on the Future of High PV Penetration so may be worth checking out for some of the attendees here. And then, the PIER program has been sponsoring us so special thanks to (inaudible) who's in the audience who has been guiding our research in the California Solar Collaborative, further CPUC and Sanyo.

Repeating these questions here, focusing on the main things that I will focus on today. One is technologies and components that we are developing, we are looking at utility issues with DG and distribution technologies and what are further directions that we

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need to take in order to accommodate the increased amount of renewables.

We've talked about this before already here today. So we have distribution system impacts off of renewable generation so that the voltage changes primarily where we may have wear and tear on all this generation equipment and potentially reverse power flows and then we also have transmission system impacts. We're looking more into the bulk system with total generation from renewables opposed to demand. There, again, we begin to distinguish between two scenarios. One is a low penetration scenario we've still in where we have some forecast errors and these forecast errors will lead to increased and reserved costs and also inefficient transmission scheduling. Rather if you go into very high penetration scenario, we may be looking at having curtailment of renewables and need storage. But we're talking much, much higher than we are right now.

People have talked earlier about data that we already have from DG systems. Actually this map shows from CCSE the metered computer systems in the SDG&E region. So actually we have here, in the red color, metered systems so we actually have a very rich database here that is collected by the CSI program to allow us to analyze already what are some of the impacts from DG in terms of aggregate generation and the correlation between different systems.

And also some of our own research at UC San Diego we have built up computer systems but also a high frequency monitoring station that allows us to monitor every second the radiance exchanges there.

Here are some examples of the computed from the CSI database of the systems in the SDG&E territory. This is 2009 data, here there were about 15 megawatts or so of PV systems that were metered at that time. This shows the two largest ramps that we found over the whole year. This is November 29, 2009 and September 29. And we see that, in generation, if we look at the aggregate generation from all of the facilities, it’s actually a very nicely behaved curve that follows the cycle of the sun. That’s not too much risk here in terms of shorter variability. But sometimes you do get rapid changes, so on this date it was foggy in the morning then it because quickly clear across SDG&E territory so resulting in a strong ramp up here of 60 percent of max in 60 minutes. And here it was the opposite in that it was clear in the morning and then it became quickly cloudy across the system and then it started on a down ramp of about 43 percent in 30 minutes.

The ramps themselves aren't really the big deals here. The question is rather can we forecast those ramps or not. If you can forecast them, then they're much easier to deal with because we can already get the generations schedule that can then take care of the over generation that will occur. So that's something that research still needs to do to see if research can predict those ramps in the days ahead or at least in the hour ahead forecasts and what conditions do we have more likely these large ramps. Is it going to be marine layer days, totally fog days, what types of conditions are causing these large ramp features. And that's still something that we're evaluating and also evaluating how good the forecast models are for forecasting these ramps.

Here's one example that's striking for California. It was mentioned earlier, that in Germany forecasting is a little bit more easier because cloud systems are visible for thousands of miles before it actually hits the country. In California we have the coastal phenomenon which are much more difficult to predict which are the marine layer clouds. There's an example here of a satellite map versus a weather model. See here the coastline and you see the satellite shows the clouds to be inland versus in the American weather model shows the cloud to be offshore. The error is small for the meteorologist, it's a 20 mile error in terms of predicting the chart front but in terms of predicting the DG generation for the time period it could be a dramatic error because much of the generation is within that narrow band along the coast.

Then Carl Lenox before from SunPower talked about the smoothing, the geographic smooth. In fact, we have study that also. But we have a very, very small area. It's about 1,200 acres but even though it's a very small area, we've already seen the effects that the variability issues are much less over the entire campus than it would be for one single site. So this just shows for one day what the irradiance was. In the morning, it was overcast, brief sunny, overcast and then cloudy again. You can see how we would expect from one single site measurement, which is the blue line, than if we had six sites we can average those six sites to see what the variability is going to be for that average. So we see it in some time periods in the morning, there was no benefit from the diversity because all sites behave the same as they'd all be cloudy or clear at the same time.

But in other times, in the afternoon, it was very intermittently cloudy but that was only at certain sites it was never a cloud that covered the entire system at once. So the green line shows you in the afternoon down ramp compared to the single system which was more noisy.

So that shows you how it’s not immediately obvious how you can characterize this geographic diversion effect but what we did is we coded all the different sites in our campus where we took the distance between the sites for the distance means less correlation and we looked at the time scale for these sites, so we looked at one second fluctuations versus ten minutes or one hour. And then divide this distance by the time scale, basically you can exactly map out the correlation would be between these different sites. So high correlation means it’s bad because it’ll all go up and down at the same time. Low correlation is good because it will basically balance out each other. We see how we can really model very well how the geographic diversion is going to occur so for small distances we see high correlation and for high distances we see a small correlation.

So we have now developed a tool based on these findings that allows us to predict for a given day how much will be the effect of that geographic diversion. So we’re looking at two examples. One is the distributed generation example that we have two sites that are smaller or we have one smaller which is larger and we look at the expected power output from these different scenarios and so the black line shows you a single panel or one sensor has a lot of fluctuations in power output but if you go to the clustered site we see a reduction already because even over one site we see some geographic diversity and if you go this site, we see even more reduction. The most sites that we put on the further we space them apart and the shorter time scales look like the more this diversion effect will occur and we will see more output from the aggregate system.

So this is now possible to now, basically, apply this to any distribution feeder or the Cal ISO grid to figure out what is the effect of geographic diversity.

Moving on to forecasting. So forecasting as you had from Germany, was very important to reduce the reserve requirements and the reserve costs with the high PV penetrations scenario. So all goals are to have interhour forecasting that's highly accurate, up to 90 percent or more, to look at forecasting enabling the spatially diverse network to be looked at as a firm generation resource based on knowing exactly how much it is going to produce.

Integration of energy storage is also plausible if you have forecasting. And finally we want to reduce the use of nonrenewable PV penetration than we'll have better forecasting.

Our focus has been on the short term forecasting, small area forecasting that we can use sky cameras to track clouds. There's a camera looking down at a mirror. The mirror reflects the entire sky into the camera, basically a fish eye, and then we can figure out where the clouds are by using image processing on a computer.

Here's examples of cloud systems that we have observed. The nice thing here versus a satellite images that you can actually really see in the middle of clouds which would just give you one single pixel over this area and so you can now see we have cumulous clouds here, lots of cumulous and cirrus clouds and the impacts of these cloud systems on different PV generations in areas are quite different because we have thick clouds or over here we have thinner clouds that are larger so they will impact the distribution generation a lot differently.

So what do we do? Once we have the clouds in the image we can basically figure out where they are moving to, that gives us these cloud vectors, then we can erect a frozen cloud field into the future and do the forecast for where various cloud shadows will end up a few minutes or tens of minutes ahead.

This shows an example of a movie, it doesn't seem to work very well, but anyways we can see here that we can project this cloud field over an area and we can see how these clouds move through the area and it actually correlates very well with what we found from our ground measurements so we can do this in very, very high fidelity over a small region.

From these forecasts, we found that we can do actually a better percentage forecasts which is unique for this technology. We also need to acknowledge that with one camera we can only see a certain portion of the sky, actually between 10-25 minutes the scene will be out of the field of view which means that's your maximum forecast view that you can use with a sky camera system. If we further develop this and we imagine looking at the LA warehouse rooftop potential then we can see there are areas in the LA basin that these PV sites can go in on rooftops—warehouse rooftops. We can imagine then basically sprinkling out a few sky cameras and cover these areas where we have the highest level of penetration to provide high fidelity forecasts over a

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larger region.

So let me finish with some directions for our R&D, some expertise from our leaders in forecasting of solar irradiation and solar power output so we can already distinguish between different timeframes and times that are important. With a day ahead forecasting, that means that for tomorrow here satellites and sky cameras are not of much use because there's too much history that goes by between the image and the forecast time so usually you use better models that you can watch it on television. Here, as we noted before there are special challenges here in California because of our unique meteorology we have the winter frontal systems that are more typical in Germany but we also have marine layer clouds and fog and all of these have dramatic effects on generation so we need to study more how well these forecast models perform in these different meteorological conditions. Then we want to develop better models so we can basically use high resolution rapid refresh simulations that can seek out better and resolve clouds better and resolve more of these fine spatial gradients that we see near the coastline where the conventional models aren't just fine enough to simulate those.

Finally, merging different techniques where satellites and sky cameras can give us information that model cannot have and we can mush them all together and get an ultimately better forecast.

Now changing timescales to interday and interhour forecasting means that two to three hours ahead but up to eight hours ahead. And that's the satellite that's usually the primary tool for doing those forecasts. There again, we could evaluate how good are the satellites for these forecasts and also look at how can we get more accurate satellite models working. For the interhour we have the Sky Imager noting that the FERC NOPR will suggest that it will have 15 minute intervals for emissions scheduling which means that interhour forecasts will become much more important going forward. However, we have a limited horizon of viewings so we need to integrate satellites and Sky Imaging to get both the fine details but also having the large view of the satellite and then ultimately looking at the models to be more accurate in simulating how, basically, solar irradiation goes through the clouds and how it's bouncing back and forth between different clouds.

I want to emphasize that we're doing all this in collaboration with industry so we're actively working with Cal ISO, Andrew Sanders working with them on solar forecasting demonstrations, we're also working with several companies that do forecasting commercially to make sure that our research is going into the marketplace.

I think you heard two weeks ago from Byron Washon, he is also a natural collaborator with us and he's keeping us real. He's telling us what's important and what we should focus on in our research.

Here are a few more things that we can focus on in terms of where are these forecasting tools going to be useful. The DSOs, the control software developers, that integrate the software into controlling inverters, the ISOs certainly in terms of increasing its ability to solar generation, also creating virtual power plants, doing tech transfer and also here another link for a workshop that just happened two months ago, the DOE CPUC workshop where the main focus was on the high PV penetration and many of these issues were discussed there.

Also finding funding sources so we're right now in front of DOE-CPUC and CEC RESCO projects looks fully collaborative and also a CSI program to conduct the solar resources and forecasting analyses.

This is my contact information. Thank you very much. I'm happy to take any questions.

CHAIRMAN WEISENMILLER: Thanks.

MS. SPIEGEL: Okay. Our next speaker is Roland Winston of the University of California – Merced.

MR. WINSTON: Commissioners, distinguished audience. RD&D is very extremely important for the advancement of any technology, and solar technology in particular, I will illustrate this and hopefully convince you of this with some examples.

We are the new Advanced Solar Technology Institute in the UC system. The previous speaker is one of our members. Our members include UC San Diego, UC Berkeley, UC Davis and UC Merced.

Our intent and our desire and our mission is to create technologies that are efficient, affordable and good for California, and in fact good for the planet.

I've already shown you who our members are and we were founded by the University of California about a year ago and our really—our mission is to thrive, prosper and grow. And we've already grown from through one campus to five in the space of just one year.

Our various members do wonderful things in technology. You've just heard the work from UC San Diego. UC Davis is involved in many technologies including PV. Berkeley is especially good in nanotechnology which has PV applications. UC Santa Barbara is famous for the nitride devices which capture the blue part of the spectrum.

I came to California from University of Chicago. One of my first experiences was with the previous Governor and then I learned what California's all about. He came to visit our lab.

We have students is really what we do and which is why I started by saying that RD&D is so important. What do we do? First of all we advance technology. We create the next technology, tomorrow's technology which is actually useful today and which is probably even more important is that we train the next generation of students who will be the leaders in this new emerging technology of energy.

I told you I'd give you some examples. One of the first things that we did was develop a concentrated PV system working with two entrepreneurs from Silicon Valley and we used our—we're good in optics. We used our knowledge in optics, their zeal to be entrepreneurs, we use the very best solar cell device available which is the multi junction cell and almost 40 percent efficient and we came up with a rather nice design which has been very, very successful. The company is located in Mountain View. They're doing very well. They're multinational, they have multi-megawatt projects in California, as I'm sure most of you know, and we take great pride in that. We started it, and one of the slide shows, with a very, very small PIER grant. Did I mention that here? Somewhere I mentioned that. From small acorns, right? So this $75,000 EISG grant produced this. Okay? One example.

The example of RD&D, research, development and demonstration.

Okay. Solar thermal. We've heard a bit about solar thermal today. It's actually very important. It's the most efficient of converting solar energy to energy that you can use. Solar energy to heat is a far more efficient process than solar energy to electricity through photovoltaics. So whenever heat is your desired end product you don't want to go through electricity, you want to go directly to heat.

What we do in that regard is that we designed solar collectors which produce heat of up to about one degree Centigrade about four degrees Fahrenheit. No moving parts so I think that those of you that are familiar with solar thermal systems expect that every eon sort of has the flat plate collectors that don't move but they're really low temperature or something that's pretty high temperature, something that's 300-400 degrees Fahrenheit maybe higher but all of these things are tracking, creaking and moving and leaking. In our case, nothing moves. These are flat, totally stationary collectors and we track with optics not with mechanical parts.

The first thing we did was develop this technology under the CEC auspices those were good days when we could go to the CEC with an unsolicited proposal, get them to listen to you and actually get this funded. I would really urge the CEC to consider that tradition, it’s a marvelous thing to do.

The reason I say that is because when you have solicitations—if you know ahead of time what should be developed, you’re really missing the important development. So what you want to be able to do is be open to new things and let those things go forward if you can.

In any case, we developed this collector. So its characteristics are 50 percent efficient at 200 Centigrade, 400 Fahrenheit. In other words, every square meter, you can think of it as a 500 watt heater at this high temperature which has many, many applications. You can displace natural gas. You can—but the application which appealed to us was solar cooling. Solar cooling is a good application because

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the need for cooling is rather well matched to the availability of sunlight, rather well matched.

So therefore we built a 25—I should say 25 kilowatts thermal collector system which powers a six-and-a-half ton double effect chiller. That's up and running at our campus in Merced. We commissioned it a week ago, I hope some of you in this room have already seen it. I hope more of you will come and visit.

That's an example of what the value is of RD&D. We develop new technology, technology that didn't exist before. We do it with the help of public agencies such as the CEC. Our technology seems to catch on. One of the students in that picture and some fellow students have started a company and now another company has also started up. So two early stage companies have already started up on this technology so I expect you'll be seeing a lot more of that in the near future.

Our Executive Director Ron Durbin is in the room and I hope you get to know us a little better and we're very glad that you're hear and that you listened to us. Thank you. Any questions?

CHAIRMAN WEISENMILLER: Thanks for your presentation and for coming today. I would say that I and Michael Picker and others visited you last year. We certainly were very impressed by the operation there, particularly for such a young campus, and I guess I was going to ask you to say a few words about the forecasting techniques developed at Merced since we just heard the San Diego part.

MR. WINSTON: I think that they're quite complimentary. The ones that we've heard from Jan are very—they're very dependent, they're very tied to beautiful instrumentation. I was very impressed by those fish eye cameras. The one in Merced I would say is more analytical. It uses very genius techniques for optimizing sort of numerical procedures, sometimes people call them genetic algorithms. I think they're a little more analytical based. In fact, basically they are a technique for trying to predict very chaotic processes which is what weather is. In that respect they're useful not only for solar forecasting but I imagine they can be turned into wind forecasting and lots of other applications.

CHAIRMAN WEISENMILLER: In terms of the thermal applications, moving back towards what you talked about, it's—California uses a lot of thermal energy and sort of major projects in terms of any of this oil recovery, some agricultural drying and obviously in some of the refineries. The question in part is what do we need to do to basically commercialize some of the solar thermal applications for those types of uses which are pretty significant uses of natural gas or oil in California?

MR. WINSTON: That’s a wonderful question. Not a week goes by when we don’t listen to and host or go visit perspective users of solar technology. I’ve visited the Bakersfield oil fields where they use steam for recovery. I think that there’s an enormous opportunity for this technology all over the state, agricultural—I’m just overwhelmed by how many things one can do with this. How can the CEC help? I think pretty much what you’ve been doing, more of what you’ve been doing. We do talk to you, we have friends in this room and I think that if I were to advise anything, I’d be open to suggestions and not always have the solution all worked out. In other words, when you offer opportunities for research, try to be broad enough so that the specific techniques aren’t always laid out beforehand.

CHAIRMAN WEISENMILLER: I was going to say, back in the 80’s the state reduced its soft oil emissions by about 25 percent by converting the enhanced oil recovery from steaming oil to natural gas so I’m assuming ultimately if we want to try to reduce our greenhouse gas emissions, the more we can shift that, and obviously production is falling off over time, but the more that we can shift that more to solar than opposed to gas or some of them are now—given the difficulties of doing CHP with the utilities historically, some of them are shifting back more to using oil and steam boilers as opposed to the more efficient gas-fired cogeneration. So again, it would seem like a rational use, the more we can use this sort of technology into these applications could have very significant benefits for the state.

MR. WINSTON: Absolutely, the temperate rate is right. The conditions in the oil fields are really ripe, I mean, they're rugged. You don't have to worry about aesthetics or anything. Just put your solar collector where you need them and when that well is all used up, you just moved it. It's quite portable. So I think it's a great application, I'd love to work on it.

CHAIRMAN WEISENMILLER: My impression was that last year you were also looking at the advancements in technology more towards electricity generation. Where does that stand at this stage?

MR. WINSTON: Well, we do have a project with the Commission on improving the DC to AC by more granularity. The micro inverter, even going down to the single cell level so that's our project with you.

Another project that is very dear to my heart is it's possible to combine—so take two seconds, this actually came from your predecessor. Art Rosenthal and I would talk a lot and he would late at night, as you know, and he would always ask me at the end "What can you do about reducing the temperature of photovoltaic panels because they get too hot and their performance goes down." Okay, so one day I call him and I say, "Art, I've got it for you. What you should do is not just try to reduce it by some special selectivity but actually cool it, cool the panels and use the heat." And we have a proposal, and we've talked about it some, where you have the combined moderate temperature, good enough for hot water but out comes electricity at the same time. So the idea is that you have—so the really good hot water solar collectors are not flat plats. No, no, no. They're vacuum tubes. That's the one that's really taken over the whole world, that's the vacuum tube collector. Now it turns out—those that depend on vacuum and selective coating. It turns out that a thin film solar material like amorphous silicon is naturally selective otherwise characteristics that make photovoltaic material much more photovoltaic also makes it transparent to infrared so it's much more selective. So what do you do? Instead of using a conventional

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selective coating on these vacuum collectors you put in an amorphous silicon and we think it's about the same cost. And suddenly every solar tube has two wires coming out and the user will have their hot water and their electricity. We think that's a rather good direction and we'd like to work on it.

CHAIRMAN WEISENMILLER: Thank you. Carla?

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: Thanks again.

MS. SPIEGEL: Okay. Our next speaker is James Zoellick from Humboldt State University.

MR. ZOELLICK: Good afternoon, everybody. I'm from the Schatz Energy Research Center at Humboldt State and I'd like to, first of all, thank the Commissioners for allowing me to participate today. It's a pleasure to be here.

Okay. Great. Thank you. So I'm going to talk today about some work we're doing up in Humboldt County, some renewable energy planning work and we're basically looking at large scale development of local renewable resources in Humboldt County. The things that I want to focus on are talking about how the work we're doing in Humboldt County can be used as a case study for local energy planning in other California communities and also talk about the analysis and modeling tools that

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we've developed to do the work that we've been doing and how that might also be transferred to other communities.

So first of all, I believe, Linda was talking earlier about the PIER Renewables Program RESCO project. The project that I'm talking about today is funded under the PIER Renewables RESCO Program and just to quickly cover what is RESCO. It's Renewable Energy Secure Community, a community that has achieved local energy security through the development of their local renewable energy resources as well as high levels of energy efficiency and there's a lot of additional benefits that come with that. Potentially more stable energy prices, more stable supply of energy, local jobs and economic stimulus, I'll talk about that a bit, as well as meeting climate protection goals and I'll also talk about that quite a bit, and certainly other environmental benefits as well.

So our project is funded by the CEC PIER renewables programs, there's some matching funds from a local headwaters fund, Pacific Gas and Electric, our local owned investor utility is one of our project partners and also contributes some in-kind cost share. The project team on this project is led by the Redwood Coast Energy Authority and Matthew Marshall, the Executive Direct of RCEA is here with me today. They are a local joint power authority, they're made up of—their Board is made up of elected officials from all of the local municipalities and then RCEA is partnered with the Schatz Energy Research Center. We're the lead researcher on this project and the, as I said, Pacific Gas & Electric is providing some data and technical assistance.

The goals of our Humboldt RESCO project are to create a strategic plan, to meet 70-100 percent of our electric demand and a significant fraction of heating and transportation energy needs with our local renewable resources. Humboldt County is a very resource rich area with regard to local renewable resources and the 75-100 percent goal is ambitious. I know there's some other California communities with similar goals. One thing, just to put in context, for Humboldt is a large part of our electricity generation is currently provided by three local biomass power plants and those plants meet, it depends on the year, but roughly from a third to a half of our local energy needs. We're a long way toward the goal of 75 percent already. Our strategy has been to develop a real bold long-term vision with these aggressive goals but also to identify real-term next steps so that we can actually start to implement things in the near term and build our way toward the long-term vision.

And our focus has also been on maximizing benefits to our local community. I’ll talk more about that. Really we’ve put a lot of focus on engaging our local stakeholders in our community and a very strong effort on broad participation from many stakeholder groups including business, finance, labor, economic development as well as environmental groups and energy and renewable energy advocates. And we feel like it’s really critical that we have that broad buy-in to really move this forward.

We think that the project that we’ve put together and the team that we’ve put together is really a successful combination. As I’ve said, the Redwood Coast Energy Authority is a joint powers authority. Their very well politically connected, obviously, if they’re elected from all of our municipalities are represented on their Board as elected officials. They’re really a public face in our community. They were established back in 2003. They provide energy planning, energy outreach and education and energy implementation services to the County. They are a partner with PG&E in the Energy Watch Program and providing energy efficiency services. And then they are teamed with myself and my colleagues at the Schatz

Energy Research Center. We bring a real strong technical leadership to the table. We feel like we've got pretty unbiased research, we are basically there to represent our community. We think that that combination is a real successful one and I think maybe other California communities may look at as well. Certainly, the JPA model that the RCEA has put together could be done anywhere and I think that there's a lot of communities that also have universities, colleges, community colleges as well that they can really engage in these kinds of joint venture ships.

The team that we've put together, we've accomplished putting together an energy element for our county general plan update. Also, coming out of that was the identification of a need for an action plan for energy and really the RESCO work that we've been funded to do is the first step in that long-term action plan. Then there's also climate action planning happening through a number of municipalities. And obviously those things all tie together.

Most of the rest of what I'm going to focus on is a couple of the tools and models that we've put together to do the analysis work. Our focus has been to look at the ability of Humboldt County to utilize our local renewable resources to meet our local energy demands. And also to look at a broad diversity of supply and demand site options and to look at what are the optimal mixes of different supply and demand side resources. The way that we've sort of defined optimal, from a number of different standpoints, but we're looking at things such as overall cost of energy services, greenhouse gas reductions and job creation and local economic stimulus.

This is a kind of a busy schematic, I'll try to go through it rather quickly. This is our schematic of our energy planning optimization model. The key inputs here are really energy demand and installed capacities of various supply technologies. On the demand side, we're looking at electricity, heat and also a need for transportation energy. We're also considering, there's a couple of arrows there that somehow got shifted out of place—they should drop down a couple of boxes, but we're looking at fuel switching measures in the heating and transportation sectors so converting from natural gas or propane to electric heat pumps and from fossil fuels in the transportation sector to electric vehicles. And we're looking at doing that because we do have a large supply of renewable resources up there and if we developed them at a large scale we're going to need to either improve our transmission capacity as a County or basically develop local demand. And we're looking at both of those things.

On the supply side, we're looking at an array of different renewable resources locally as well as power from the new PG&E Natural Gas Power Plant that was just repowered and is very well suited to follow intermittent renewable. It's 10 16-megawatt combustible engine generators. And then balance support, look at import/export electricity storage is something that we've been considering as well, as well as load shifting on the demand side.

So we've run this model, it's essentially a single node energy balanced model, sort of a dispatch model if you will. We make sure that each hour of the day, we're meeting the demand with the available supply, depending on the mix that we've come up with. We do this over a year's period and then in post-processing, we look at the overall cost of energy for the resource mix that we've come up with, job creation impacts and other local economic stimulus impacts as well as greenhouse gas implications. And so we're basically then able to wrap an optimization algorithm around this and we're able to reiterate and key-in optimal mixes based on some of those criteria. Here's an example, and again it's bit of a busy slide but I'll talk you through each of the sections of this. On the right hand side is an optimality curve. So what we've done here is establish a business as usual case so the access, the horizontal access, is cost and percent of business as usual starting at 100 percent. And on the vertical access is carbon emissions and percent of business as usual. And so, for instance, where the red circled dot is there, we've allowed the overall cost of energy services to go up by about five percent and then run the model through a whole bunch of different potential resource and demand mixes and look for the lowest carbon emissions at that five percent cost increase and so off to the left-hand side you can see the supply and demand side measures that were arrived at. On the supply side, on the top there, there's capacity so it's not energy provided but just the capacity available. So the natural gas plan is the existing plant, it's 160 megawatts. That's about 60 megawatts of new wind power that does not currently exist. Biomass is shown there at about 120. We've got about 60 megawatts currently so that's doubling our current biomass capacity. We're quadrupling hydro from about 10 to 40 megawatts. And then the import/export capacity shown there is the existing transmission line in and out of the county. On the demand side, we're basically maximizing our efficiency resources and then that’s showing heating and transportation, penetration of heat pumps and electric vehicles in those two sectors at about 35-40 percent. And on the bottom we end up with, in this scenario, about 20 percent of our energy provided by natural gas, about 10 percent by wind, about 50 percent by biomass, about 15 from local small run of the river hydro and then the final 5 percent from efficiency gains.

In addition, so we do have sort of a simplified version in that optimization model of jobs and economic impacts. We have a more rigorous analysis of jobs and economic impacts and this is basically a standard economic input/output analysis that we’ve done. It utilizes the inplant multipliers and we’ve developed models for biomass, wind, small hydro, distributed PV, the natural gas engine generator power plant we’ve got and energy efficiency. And we’ve done this—we’ve utilized where available NREL’s Jobs and Economic Development Impact or JEDI models. Those are available or at least when we needed them within a few months back. They had one for wind that was completed, distributed PV was completed and they had a natural gas one that we had to modify somewhat, biomass and small hydro they were working on but those weren’t done so we basically reverse engineered and developed our own biomass and small hydro models and then energy efficiency, as far as we know, there’s nobody that has a sort of JEDI type model for energy efficiency so we developed an energy efficiency model. All of these were customized for Humboldt County so the economic input/output parameters are customized for Humboldt County and we think they’ve given us a pretty accurate estimate of the potential job impacts.

This is a sample so that the optimization scenario that I showed you a couple of slides back with the red circled dot, this is that same scenario. This is showing the net jobs impact for the community based on that scenario. So you can see both construction phase and operation phase, job development across the different resources. I think what jumps out is both biomass and hydro as being big job generators. Certainly in the operations phase of over the lifetime of the facility, biomass is the big one in terms of jobs. I think this is going to hold true for any rural county, rural community, with lot of biomass. Basically, the fuel source is local, the labor force and the equipment and basally everything that is needed to harvest this as an energy resource is available locally. I suppose for us if we’re putting in wind turbines we’re not going to be building those turbines locally but—so biomass really generates a lot of local jobs. And here, this was about, net creation of about 400 construction and about 130 operators based jobs.

Just wrapping things up here, so some key lessons that we learned so far in the analysis work we’ve done is that we think we can meet a large fraction of our energy needs using local renewables and in the process, substantially reduce our greenhouse gas emissions. One thing that we found actually is maximizing the percentage of local renewables is not necessarily the most cost effective or cost efficient way of going about reducing greenhouse gas emissions so I think it’s important for us to think about what our goals really are that we’re trying to achieve and maybe sometimes if we have a percent renewables goal, there might be a point where we might want to relax that if we feel that there is something else we can do that might actually get us the results that we’re really looking for. In this case it might be climate change impacts.

We think that we, from what we’re looking at, that we can do this as a modest cost increase and in the process also create a lot of local jobs and local economic stimulus so potentially a net benefit to the local economy. We came up with a lot of possible resources and technology options. As I said, we have a pretty broad mix of resources up there. I think that there are some optimal mixes but likely some sort of diverse mix would make the most sense. In any case, it looks like that biomass, wind and run of the river hydro will likely play a big role. Electric vehicles, the adoption of electric vehicles and heat pumps, we think is really critical to doing this cost effectively and to lowering our greenhouse gas emissions. Certainly energy efficiency is the key place to start. And distributed generation, and I think most of the projects that we're conceiving and looking at up there, I think can be considered distributed generation. Most of the probably below 20 megawatts. But in terms of at the customer site, behind the meter types of distributed generation, we think that they can play a smaller but important role and one thing that I think that we see, and I've certainly heard this today, that there is a tremendous amount of interest and support in our communities for distributed generation. And I think if, for no other reason, there are technical reasons why it makes sense. It's not always the most cost effective but I think there's a lot of public support for it and I think, certainly for us in our local communities, building support for this renewable energy and energy planning vision, including distributed generation in that mix is important in terms of engaging our local community.

Finally, just some thoughts on opportunities for further research. In terms of the modeling work that we've done, we feel that we could put this out and adapt it for use in other communities as well. We've actually already been approached by the City of San Francisco's Department of Environment who's interest in perhaps utilizing the optimization model that we've put together. It's going to take some work to—it's been a very customized thing to date so it's going to take some work to adapt it for them but it's certainly possible. Ultimately, we'd like to put together a friendly user interface on it so that it could be more easily accessible for other communities. And then there's certainly—it needs more peer review and there are areas where I think it can be improved or expanded, one of them in regards to the discussion today about distributed generation and we do not look right now at combined heat and power opportunities, and that's something that we certainly could add. And then, as I said, to start with I think that some of the lessons that we're learning in Humboldt may have value to other communities just as a case study. We're a pretty isolated community up there and so reaching a large percent of renewables on the Humboldt grid is something that we can do pretty quickly given that we're already at a large portion with biomass and it's sort of a place where some of these issues with stability on the grid could be done in the area that we're in in a pretty controlled environment because we're so isolated.

We have done some work with PG&E and we're looking at doing some just very preliminary power flow studies, interconnection studies for some of these portfolios that we're looking at in terms of a number of local renewable projects. And certainly that's an aspect that I think we certainly haven't gotten much of an estimate of cost from them yet. They're going to try and come up with a first order estimate for us. That's something that's certainly going to add to the cost of what we're looking at.

And then finally biomass, as I said, is really a key for our community. I think one of the places that we can certainly expand the utilization of biomass as a resource is in fuel reduction materials. Most of the waste from the current temperate product industry, the mill waste is utilized and has been utilized for years. It's very low hanging fruit. It's available there at the mill once they mill the lumber but the fuel reduction efforts, in terms of reducing fire hazard, and there's a great push to do this by the California

Department of Forestry and others but it's expensive to go out there and reduce the fuel hazard and then they end up with piles of slash that sometimes they can't burn. So figuring out ways to make that economically viable as a fuel is, I think, an important thing. And one option that we're looking at in Humboldt and we're partnered with a start-up down in the Bay Area right now is a process called torrefaction. It basically densifies the resource, essentially turns it into a very high energy charcoal type material. It's very stable. It's hydrophobic and it may be a way to more cost effectively getting that diffused resource to energy plants, be it distributed generation or larger central scale generation.

That's what I have for you today and I'm happy to take any questions.

CHAIRMAN WEISENMILLER: I have just a couple. One of them is in terms of your model structure, is it a linear program model, power flow production cost. What kind of program is it?

MR. Zoellick: Well, it's –

CHAIRMAN WEISENMILLER: Combinations?

MR. Zoellick: Yeah. It's an hourly model. On the supply side, we have hourly wind date, hourly wave data so we're actually modeling the stochastic nature of the resources. And on the demand side, I think we have five or six year’s worth of data from PG&E, 15 minute interval data so also some stochastic simulation on the demand side of things. And then, the cost part of it is basically based on lifecycle costs and data from the CEC on production costs of different renewables. Basically, there’s an energy balance on an hourly basis and the optimization routine is an evolutionary optimization algorithm that basically that tries to zero in on the optimal solution.

CHAIRMAN WEISENMILLER: Other suggestion was that in talking with PG&E of potential joint efforts, I’m sure they’d be happy to catch up with you on it.

MR. ZOELLICK: And David is on our Professional Advisory Committee and has really been the key person with PG&E that we’ve been working with. He’s helped us get a lot done in terms of if we need information or data or technical assistance, so he’s been a great help.   We’d loved to continue to work and partner with them.

I think one of the things about—for communities to be able to do this stuff is communities being able to have some choice of where their energy comes from and it’s great to do the planning but if you don’t have the ability to make some choices then it’s not really all that useful. Certainly, there’s some communalities looking at community choice aggregation and that’s been something that people have talked about in our area as well. Our feeling is that that’s not necessarily for every community. We’re also interested in exploring other avenues of partnership with the investor owned utility. Even ideas such as a green tariff where local business, local ratepayers could purchase renewables and even renewables from local projects where they see the value of developing these local resources and being able to purchase that energy without having to establish a community choice aggregator. We’re certainly interested in looking at any sorts of options that the utility commission and other would be willing to look at with us.

CHAIRMAN WEISENMILLER: Well that’s great. Certainly David is the one to work with at PG&E. That’s good that you two are working hand in glove on this.

MR. ZOELLICK: Thank you.

COMMISSIONER PETERMAN: And I had a similar questions about the model because I was trying to understand how you incorporate the electric vehicles demand in here and thinking in particular how do you think about vehicle supply versus solely on the supply side?

MR. ZOELLICK: Right. Well so the electric vehicle model was based on, I believe, some EPRI. In terms of penetration rates and what may be possible, I think some of the work done by EPRI but also there was as study in Oregon for—was it eTec and we actually felt that the work done up in Oregon was, in terms of our northern and rural nature, that that work was quite a bit more applicable. We basically drew on that information. One of the people on our Professional Advisory Committee was at Davis in their Institute for Transportation Studies, he's helped us out with that electric vehicle piece of it. We also utilized the information, in terms of the vehicles themselves, their efficiency, the charging characteristics and basically tried to put together our best estimate of what that would look like. At this point, we do have the ability to do some demand response. It's a bit crude at this point so we don't really have full smart grid price responsive type of interaction at this point.

COMMISSIONER PETERMAN: And also did want to mention that at the business meeting last week, we approved funding for a sustainability study of biomass collection to be done by the U.S. Forest Service. I think that'd be a nice compliment for the work you all are doing in Humboldt.

MR. ZOELLICK: Okay, great. That's something that we should look at. Just one other thing, I know there was a comment, I believe it was when the woman from Sonoma was speaking. You talked about looking for ways to kind of connect communities. I know we've participated in the RESCO symposium over at Davis the last couple of years but by all means if there's a venue for us to come together with other communities, learn about what they're doing and share what we're doing, we would be very interested in doing that.

CHAIRMAN WEISENMILLER: That would be good. As Picker indicated earlier, I guess it was more or less in the first panel by our first speaker, certainly we've been talking to the Governor's Office about trying to have an event where local communities, more later in the summer whether that's July or August, working with the Governor's Office and the UC on that.

MR. ZOELLICK: Okay, great. Thanks very much.

MS. SPIEGEL: Our fourth speaker today is William Torre from San Diego Gas and Electric Company.

MR. TORRE: I'm Bill Torre. Hi. I spoke earlier today. I'm representing SDG&E. I'm Chief Engineer and Manager of R&D activities in the electric transmission distribution engineering at San Diego Gas and Electric Company. We’ve been conducting R&D to accommodate DG for the last few years. I will be talking about DG integration and some concerns we have about achieving the 12,000 megawatt DG goal and some of the R&D and demonstration projects related to mitigating the impacts on the T&D system caused by high penetration of DG.

In our system, the DG is connected to our distribution system of 12 KV and consists of mainly of rooftop solar photovoltaics. This slide summarizes some of the concerns we have regarding DG and I’ve already talked about some of these previously in—when we talked about European utilities.

On another slide later in this presentation I will list a more complete list of the issues related to high concentration of DG. Under operational concerns I would like to emphasize the issue of ensuring resource adequacy and ability to monitor DG output. This will be important if DG is going to become a significant portion of our resource mix. Also, the impact of DG is highly locational dependent. Installations in rural areas with weak distribution lines tend to have more voltage regulation and power quality problems due to DG. We have a number of concerns regarding the planning of electric distribution facilities accommodating higher levels of DG. Volt VAR planning and ensuring adequate planning to meet the existing CVR and ANSI standards is a concern. A short list of mitigation measures is also provided here to address voltage regulation concerns and monitoring of DG. Developing and requiring smart grid inverters to ensure future DG may address both of these concerns.

In this last I'm talking about the technical studies that we have done related to DG. We have completed a couple of internal studies looking at steady state impact of high levels of PV. Listed here are technical studies that are being conducted simulating high levels of PV on SDG&E's distribution system. One by EPRI, one by Quantum Technologies and another one we're doing jointly with UCSD and EDSA as one of the contractors which is funded by DOE.

SDG&E is also conducting some demonstration projects. Our RD&D demonstration projects to test technologies to accommodate high levels of DG. Our microgrid project in Borrego Springs, which is funded by DOE and CEC, will demonstrate the feasibility of automated balancing of load and generation at a local level. We'll also be investigating an automatic volt VAR control. Another project that we have ongoing is that we will be testing a new type of solid state dynamic voltage support on the existing distribution circuit that is experiencing voltage problems due to a high level of DG. In fact, I'll show you a few of those graphs in a few minutes on the voltage how that's being affected by the high level of DG.

Another project we have is we also will be testing energy storage equipment as a way to smooth intermittency of PV on distribution circuits. We have three separate projects investigating energy storage. Each testing a different technology. And we are also looking at other energy storage technologies.

This slide shows some of the planned projects that we have going forward. In addition to demonstration projects we're also looking forward at incorporating higher levels of DG to meet the 33 percent renewable target. In our general rate case, we've provided for several projects that will help mitigate intermittency, voltage regulation impact and provide more observability for system operations on the status of DG operation.

This map shows the existing PV that's installed in our service territory. We have 12,798 locations of photovoltaics. Roughly 80 percent of this is in the coastal region. This represents about 99 megawatts of PV generation to reach the 12,000 megawatt goal would require us to increase this 99 megawatts to about 1,000 megawatts. That's a significant increase. This map shows our locations are quite diverse and at present time, there's no control over location.

Additional impacts—this slide has a more detailed list of additional impacts. A lot of these have been discussed today, earlier during the first or second session on European impacts. This slide shows more impacts and how they're caused by high level DGs. These included impacts on our voltage and associated voltage regulation equipment, our protection of relaying and accommodating reverse power flow at short circuit levels. The impact of intermittency in the ability to accurately forecast DG in the resource mix, the impact on energy efficiency and increased system losses, possible upgrades required of distribution circuits to prevent thermal overloads and potential power quality problems and changing work practices to accommodate higher levels of DG.

This slide shows a daily and actual data taken from one of our circuits that has a large two megawatt PV plant at the end of the 12KV circuit. This particular graph shows the daily cycling. The top graph shows the daily cycling of voltage.

One thing that I wanted to say is that the impact of intermittency is a serious concern. It's kind of like not understanding cancer until you start looking closer, under the microscope and then you realize that it can kill you. The following two slides show you successive closer shots as we kind of hone in at looking at one particular voltage graph. The top graph shows a succession of 21 days of voltage cycling on a distribution circuit. If you take one of those snapshots and blow it up to a 12 hour timeframe and you can see there's quite a bit of variation within that timeframe.

By the way, when you look at the timeframe here, this also happens to be in the timeframe of the reaction of our LTCs, load tap changer voltage regulators and capacitors. So during this timeframe, you're having capacitors switch on and off, load tap changers go up and down and voltage regulators constantly adjusting. And you can imagine that this is kind of like driving your car and slamming on the brakes every so often. You can imagine how much wear and tear that would be on your equipment.

Now, if you take just that one 12 hour period and you take a short period, like a 5 minute period within that, you can see that there's quite a bit of variation right within that 5 minute period. In fact, during a steady state period there shown on the left there, it's actually outside of our CVR limits which are required in our ANSI limits. We've worked really hard to meet this CVR goals to maintain system efficiency. This is actual data from PV that's connected to our distribution circuit, which is driving us out of that range.

Some regulatory concerns, we believe that there's a need for some changes in the regulatory statutes and some of the industry standards in order to accommodate future penetration of DG on our electric system. Rule 21 and W-DAT need to be revised. Some of these changes include adoption of new thresholds for allowing PV connection considering off peak periods instead of just on peak periods which is used at present.

PV output generally peaks before our peak load requiring low voltage ride-through, which is also important, and frequency group control. I think I mentioned these earlier. And control of monitoring capability similar to the European requirements today. Rule 2 will also need to be modified to include changes to harmonics and voltage requirements. One of the things that I did notice in the European standards is the harmonics requirements are much tighter than ours here.

Regulation needs to be considered in how the cost for T&D upgrades for higher levels of DG should be paid for. This is a cost causation issue. And also modification of industry standards are in the process and need to be completed to adopt the use of small inverters for PV that will have advance control and communication capability. Earlier IEEE 1547 and UL 1747 was mentioned. And also we need to modify W-DAT to accept smart inverters.

In summary, increasing the level of PV penetration with present regulation requirements will have a significant cost to accommodate them on the electric transmission distribution system. SDG&E is proactively conducting R&D to include technical studies and demonstration projects to evaluate ways to mitigate the impact of high levels of DG. The potential impact is real. We have measured the impact on our system. We believe the changes are required in regulatory and industry standards to accommodate the increased levels of DG. Also, I'd like to say in closing that the DG, the closer it is to the substation the less there is in the cost impact. Thank you.

CHAIRMAN WEISENMILLER: Thanks, Bill. In the interest of time, I'll just ask one question. You heard

Heather's earlier discussion on the ISO tariff treatment at FERC, obviously that's sort of an ISO issue, a national issue of depending on whether the DG is on—which side of the wall it's on between FERC, ISO regulated PUC regulated. What can we do on the federal side with FERC on that sort of tariff provision?

MR. TORRE: FERC is generally—has jurisdiction on the transmissions here in California and most of the distributed generation here is on the distribution system which is out of FERC jurisdiction.

CHAIRMAN WEISENMILLER: That's true. As you know there's a real hodge podge between which transmission systems are deeded over to FERC regulation when we went through 1890 so certainly it's hard to generalize say from SDG&E to Edison to PG&E what circuits are where.

MR. TORRE: Well our distribution system is 12KV. Whereas with Edison, theirs is 69KV system, since it's radial, is considered part of distribution system. There's a difference there. Seems like the appropriate place to have that change in regulation is in the Rule 21 which is under CPUC jurisdiction and that would be the place to make the changes, I think, and W-DAT as well.

CHAIRMAN WEISENMILLER: Okay. Thank you.

MR. TORRE: Anybody else?

CHAIRMAN WEISENMILLER: Thank you.

MS. SPIEGEL: Our first speaker on this panel is Peter Evans with New Power Technologies.

MR. EVANS: Thank you all for staying. I' try to make this interesting.

CHAIRMAN WEISENMILLER: I was going to say, you do get the last word, right? In the public comment.

MR. EVANS: Actually what I'm going to talk about is sort of interesting. It's an example of some foresight in the Energy Commission, specifically in PIER, now quite a number of years ago that saw ahead and saw the need for some tools that I think are just now coming into their own.

At the time we were asking was DG good or bad for the power delivery network. It's basically a religious question. So how you felt about the answer to that question depended on your point of view. So we've changed the topic a little bit for the purpose of this session today where we're not even talking about the power of the delivery network. We're just saying DG. So it really is still and we've heard it, heard it and heard it over and over today is that it's still all about the grid.

What we've tried to do with the guidance and support of PIER back in the early days in the work that I'm going to talk about is to reframe the question. Specifically, how does a particular DG project effect the grid? This is one project. How does one project effect the grid? And if you know that, you know everything that you need to know about all of the projects.

Where can DG projects interconnect without the need for costly upgrades? How many times have you heard that today? That actually wasn't one of the original questions but I put it in anyway because it's timely.

And then which DG projects improve good performance? So this has to do with, I think, somebody in one of the earlier panels used the term something like micrositing or it's knowing what happens with one project and one location and if you know that you know everything that you need to know.

And then the last thing, and as policymakers we should care about this, can we rigorously value a DG project's direct benefit. It might improve reliability but actually does this particular project, actually improves reliability this amount. And if you know, then you can design incentives that fairly exchange value among the participants.

So let's talk about the grid a little bit.

This is a real system, it's actually part of the Southern California Edison System, about 1,000 square miles and serves about 280,000 customers. When you think about this as a system this is pretty much what you see.

And there's distributed generation in this system. If we go to 12,000 megawatts, there'd be a lot more. Here's the thing. These projects aren't floating out there. There's a whole infrastructure underneath that we really have to understand at a very granular detailed level, still part of the whole system, but down to the individual line segments, individual pieces of equipment, individual devices, individual connection points in order to understand the impacts of these projects on this grid.

Every DG project and every location has a unique impact. And so that's the vexing problem, that's the reason why interconnection studies take forever to do and that's why there's big backlogs and that's why we talk about all these concerns. That's because each one of these things is unique.

So the technology that we developed with PIER support, since 2002, is this energynet power system simulation. This is an area wide simulation of an integrated transmission and distribution network. It's basically all the white stuff that you saw in the prior slide.

This is a single model and a single simulation that determines the power flow through every line segment and the voltage at every position in the system. The model is produced and upgraded by software directly from routinely maintained legacy utility data. So this is armies of people pouring over drawings. It's a stack of CDs that go into the computer and out comes the model.

The legacy field sensory data is fully integrated so people who talked about situational awareness. If you have all the field data integrated into the model and a single simulation running, you actually know exactly what's happening in the system under any set of conditions, in any location, at any time. And the single simulation results are validated with field measurements. So this was all demonstrated through a series of PIER grants beginning in 2003 and finishing up, actually the most recent one noted here was completed in 2009.

But with this tool we can assess grid conditions at any point in the network, under any operating scenario and we can view direct impact of any change at any point in the network. If you want to add a project, what’s the change. If you want to change the (indiscernible) what’s the change.

DG has a number of impacts, I’m going to go through this quickly because we’ve heard that about this pretty much all day, but I think it is important to be sort of disciplined about really what are the direct impacts of these projects for two reasons. One is you want to be sure that you’ve considered them all. And we’ve heard a lot about voltage which when Rule 21 was first framed, people didn’t really talk much about voltage. A lot of project evaluation goes on without direct consideration of voltage. You guys are experiencing it. So it’s important to look at all of the categories, all of the impact categories not just the ones that happen to be named in Rule 21 or the FERC SGIP Fast Track. And with the ability we have to look within an individual circuit—people say location matters. Well location really matters. This is kind of a look inside a circuit the way we look at them because we have the granular of every individual line segment and every individual point of every individual circuit in a system. So you might do this hundreds or thoughts, or PG&E might do this 3,000 times and this is a particular path. So within each circuit you have multiple paths because they’re like trees.

These are individual potential points of interconnection running out from the substation and what this shows is, people talked about strength today, so this is a measure of strength or weakness. There's also thermal ratings of the individual lines segments, those are the blue ones here. And then there's the circuit minimum load. This is the load that you would like to not exceed if you were to avoid reverse flow.

So the question is how much PV or where can we put a PV or DG project on here? Well, if we limit it to minimum load you're going to hear around six megawatts but any point on the system. And then we'd like to avoid the weak areas. In this case we used a measure of weakness that's reactance over resistance, it's a ratio of the—there's a bunch of different ways to measure this thing, but if you have the insight of the whole, of every line segment you can calculate these things.

So this is going to eliminate some of these points of interconnection. And then, these last few parts of interconnection here, because the thermal irradiance of the conductor is smaller, than those projects would be limited as well. So pretty quickly, we can determine at these points, we can interconnect projects of up to a certain size, each point is a little bit different potentially and it's likely to have a minimum impact. Both in terms of voltage and in terms of overloads. And that's just a quick look.

Suppose I want to put a parking lot project in this shopping center, this is one of those circuits that is modeled within the system, and wants to be interconnected at that particular location. It's a mouse click to find all of the characteristics of that location, including the controls in the substation, whether it has a load tap changer, whether it's three face or grounded and what the XOVR is at that location, how weak or strong that particular location is.

And then with a second mouse click, I can drop a simulation of that individual project into a power flow, resolve it and determine what the voltage impact is. We heard some numbers today like 1,2,3 or 4 percent change in voltage at the project location is considered okay. Here we can actually ell what it would be for a given project. So the evaluation of the project takes about as long as I just described.

Sub circuit detail levels are important. You can't just look at a circuit. You have to look at the location on a circuit. These types of analytics can help us to identify low impact sites throughout our entire system. We just completed a project for CEC where we looked at this particular power system and identified 83,000 potential locations to interconnect large scale PV projects and we identified within that group 34,000 locations that met all of a pretty rich set of criteria. And we did actual simulations of about 535 individual projects at every one of these circuits. That was a large project in terms of the actual issues we evaluated but it's comparable to the backlog of a best run utility and they're looking at their W-DAT backlogs.

So of course we have a look at the voltage conditions, and this is going through time, hour six, hour eight for this particular system on a particular day. And we also, using some fancy analytics, can determine locations where there's particular types of resource deficiencies. And we can use those—that information to determine, in this particular case, it's pretty hard to read but these are individual projects—or individual circuits in this system. There's 246 circuits in this system and there's a group here that have an unusual vulnerability to random outages. So they're basically less reliable.

So we can use these types of assessments to go through and determine where DG projects can yield specific types of operational benefits. And we can come up with a portfolio of projects that will maximize grid performance and we've done that in these studies.

And then I would argue that—we have projects that have low impact, we also have projects that yield specific benefits. So now the question is what are these benefits worth? I didn't come up with this list but I really like it, it's a list of benefit categories and in fact, I would argue if that your rule is a benefit to be real has to be quantifiable and priceable, that this is a complete list and any given change to a system will have an impact on one or more of these areas.

So for example, we went through this system that I just showed you and identified 24 circuits where DG projects, individual DG projects, would yield certain types of benefits. You can see here that most of these benefits relate to reliability improvement. The reason why reliability improvement is such a big deal is because most of the reliability pain in this particular system has to do with the ability or the inability to shift load after a contingency. DG projects on a particular circuit may open up a capacity for it to take load following a fall where otherwise it didn't exist. And now that sister circuit is more reliable.

These are all the benefits that these particular projects yielded in all of these categories.

We can do a direct comparison, those projects are actually aggregated in this stack, with controls, resetting the controls for this system, network topology, the addition of three capacitors and you can see these are the value in a single year's value, adding up all of these benefits.

And then this is a comparison of those projects with a set of projects that were actually planned by the utility. And you can see that some of the utility projects didn't yield much in terms of benefits and others yielded a lot. What's interesting to me actually in looking at these is that the colors are different. What that tells me is that the DG projects and system expansion projects both yield value but it's different value. It's not one of the other, they're complimentary. There's some things here like load relief that are very difficult to get from a DG project but if you put in a new substation it provides that.

A detailed system simulation like this can reveal the direct grid benefits of a particular DG project. It can also compare dissimilar projects along a common set of values and actually that could be applied to any grid investment, it's not just DG.

I think this is a great story, of course I have to, this is my project but I think it’s a great story of PIER folks having the foresight years ago to invest in something that actually took a long time to develop and was quite difficult but now we can talk about it. So that’s a great story for PIER. There’s certainly opportunities to extend this type of thing. Any tools that help to understand and manage the interplay between grid and DG or any attempt to understand that interplay requires tools that provide better grid visibility. That’s what this tool does and there’s certainly opportunity to develop other tools that provide that. All of these challenges that we talked about today would be easier to address with greater visibility into the specifics of the impacts.

And then the second thing that I didn’t really talk too much about but I think, personally, is really important and the PG&E guys said it. They said their system is reproducing itself about one percent per year. So the legacy stuff that is out there is going to be out there a long time and I think anything that anybody invests in has to work with the legacy data, the legacy systems and it has to be easy to adopt because there’s risks involve that may not work and you have to play well with what’s out there already.

And then I think it’s not really R&D I guess but I still think it’s important. The DG proponents and the utility customers realize that most of the benefits of DG but utilities bear most of the risk. That set of incentives or misaligned incentives as a policy matter should be addressed and maybe there’s research that goes to better understand that. But I think that this is actually a relatively big barrier. We can talk about all the things that could be done but in the end if the incentives are cross wised between the participants then it won’t happen.

In terms of tools such as the one I just described, if you have rigorous measures of the direct benefits of a particular thing, you know for sure this particular thing will yield these kinds of benefits and it’s worth this kind of money, then you have a basis for rational cost sharing and incentives that allow you to exchange value among different participants.

So that’s all I had.

CHAIRMAN WEISENMILLER: Thanks. One thing that would be interesting, from my perspective, to talk about is you mentioned that the utilities bear most of the risk. I guess that’s a good questions to define exactly what risks do you see for the utilities from DG?

MR. EVANS: I guess that’s a good question. I should have been more specific when I said this. This set of benefits, the benefits that I listed, were economic benefits. And some economics benefits accrue, for example, accrue service quality as an economic benefit to some types of customers and they realize that benefit and they keep it. But if there’s an economic benefit to the utility in terms of cost reduction, that ultimately turns into lower rates. At least for an investor-owned utility, it ultimately shows up as lower rates. So if the utility adopts something, like a distributed generation project, or some new method like this method and it turns out not to work and it ends up reducing reliability or resulting in unexpected costs, then the utility is at some risk and it could be real or it could be perceived but there is some risk if that occurs. When I say the risk it is a little bit intangible, I suppose, it could be a disallowance. There isn’t really the financial benefit to adopting new practices or taking on new technologies or doing things different ways. The financial upside accrues to the other participants, it really doesn’t accrue to the utilities.

CHAIRMAN WEISENMILLER: But again to push you on that, in California we have decouplings, so to the extent that DG reduces sales. And presumably they’re indifferent on that and obviously utilities profit mostly through rate based additions but that typically these may or may not displace utility rate base or they may add to it but just thinking about it, it’s hard for me to generalize and say that this is really going to chop out utility rate based additions. Certainly reliability and safety, again, are two of the key things for regulation and utilities so it would seem like there would be risk questions to become does this affect reliability or does it affect safety? Or do you at some point raise rates so much that you have some sort of rate revolt to be a potential risk that a utility might be concerned about?

MR. EVANS: Yeah, I guess—well, I don’t want to go off on too long of a tangent this late in the day but I think it’s a great set of questions. I think that it’s a good topic. Part of the way that I think about it, and I’m an ex-PG&E person so I’m pretty sympathetic to the perspective of a utility, is first of all reliability is pretty good and safety is pretty good. I’m not sure there’s a lot of money out there for utilities, at last in California, to achieve dramatic improvements in those things. It’s really more downside exposures than the upside of opportunity. And then the other thing is when we talk about things like new technologies and leveraging legacy systems, in some ways what that's doing is that you may miss out on an opportunity to expand rate based because you're repurposing existing assets or you're getting new value from existing assets by using soft expenditures like software which don't really add that much to rate based. A utility might say, "Sure that sounds great but if I can just replace everything then I can add that to rate based." I'm not sure that the utilities would actually say that but it's easy to see how there's a financial argument that says they should.

CHAIRMAN WEISENMILLER: It's late but certainly in terms of written comments, anyone who wants to dig into that more, I'd be interested—I was going to ask Bill the proverbial question, I don't know how much—do you have a similar model on your system? I don't think you've had much of a chance to vet this model in advance.

MR. TORRE: Of course we have load flow programs, we do have some linear programming at circuit analysis, we don't have this particular model that he's talking about. But it sounds interesting. We are developing, like I mentioned earlier, a mapping system for mapping available capacity in locations so I would be interested in this to learn more about it.

CHAIRMAN WEISENMILLER: I tend to think as we move forward on DG that, again, a bunch of modeling tools that we've talked about like forecasting the weather but anyway we need to have the sort of model development and communication among the different parties to get to the best and to develop the types of models that we're going to need eventually.

MR. TORRE: I agree.

COMMISSIONER PETERMAN: I just agree with that as well in particularly being able to model some of the environmental characteristics that we mentioned earlier that would be useful for an environmental screen. I don't have any follow-up questions but yes, that was interesting. Thank you.

CHAIRMAN WEISENMILLER: Thanks again. And I guess now we're at the public comment phase.

MS. SPIEGEL: I would like to thank this panel for the very interesting summary of your research.

CHAIRMAN WEISENMILLER: So would we.

COMMISSIONER PETERMAN: And actually, I feel more optimistic after this panel because we've spent this morning thinking about a lot of the challenges and it seems that we have researchers who are already working on it. So, well done.

MS. KOROSEC: All right. I have three public comment cards here. I'm not sure if people have held on to the bitter end here. The first is Cecelia (indiscernible). No? We've got one who's bailed on us. Next is Danielle Osborn Mills from CEERT.

MS. OSBORN MILLS: Good afternoon, Commissioners. I'm Danielle Osborn Mills with the Center for Energy Efficiency and Renewable Technologies. I would like to thank you for getting these panels together today and the entire workshop, it's been really great to hear different agency perspectives and ideas on how to work toward the 12,000 megawatt goal as well as to hear from different stakeholders.

I just have a couple of quick points. Today's conversation first has been heavily focused on solar PV and that's great, I understand why it's obviously sort of developed more than the other technologies but I do want to emphasize the importance of a diverse set of technologies on the grid for the variety of benefits that they can contribute both to customers and to the grid itself. Each technology has its own value, its own environmental benefits, has a different profile and different applications because of that. So we just want to emphasize consideration of fuel cell technology, solar heating and cooling and things like that, micro turbines.

We also believe that planning for achievement of the 12,000 megawatt localized generation goal should focus on sort of the transition to a cleaner grid and also the displacement as Bernadette mentioned. In the long-term we're looking forward to other workshops on transmission planning and some of the more technical issues.

We also see additional value in customer side installations and I want to, again, echo Ms. Del Chiaro's statements on that. I think that heaving half of the 12,000 megawatts come from customer side would be a great goal, especially when you consider that a lot of that is already online.

I'll save the additional comments for the end but we're looking forward to future workshops and happy to see the progress that you've made so far. Thanks.

MS. KOROSEC: Last card I have is for Ray Pingle from the Sierra Club.

MR. PINGLE: Hi. My name is Ray Pingle from the Sierra Club of California. Again, thank you very much for this excellent workshop today. We greatly appreciate and support Governor Brown's Clean Energy Plan and particularly the 12,000 megawatts for distributed generation as supported by renewable power payments also known as feed-in tariffs. And I just wanted to bring up feed-in tariffs because we really haven't had that much discussion of that today. I think that probably most of the people in this room have read all kinds of studies and documentation that has proven that the single most cost effective and effective in bringing up large values of renewable energy quickly is a best practices, cost based feed-in tariff program. NREL states that 75 percent of solar and 45 percent of wind has been financed by feed-in tariff programs. We believe that the existing feed-in tariff programs in the state are too modest in size and have pricing mechanisms that are suboptimal in their effectiveness. The existing AB 1969 program, for example, is a very modest program today with 500 megawatts. And even with the SB 32, once that ruling is achieved we'll be only 750 megawatts. Through the Ram program, which we think is a step in the right direction, but it's only a step. It still has—the good news is that it has a 20 megawatt project size. But it's still a modest program in size with 1,000 megawatts. And we recognize that the PUC does have the discretion to expand the duration and size of that program so if that authority is exercised, that would be a good thing.

It has a bidding mechanism opposed to a cost based feed-in tariff mechanism. In deference to the administrative law judge that issues that ruling at that time, that was probably the best he could do given the understanding at that time of FERC limitations, but now with the recent FERC orders in the last six months, they have clarified the latitude that states have to create categories of different types of energy and then have competitive pricing within each category. This effectively allows the state to establish multi-tiered pricing structures which is very close to a best practices feed-in tariff program.

We would just really request that the CEC, working with the PUC, the Governor’s Office, legislation, all of those appropriate work towards a vehicle—either using a vehicle—a legislative vehicle or a regulatory process to put in place a best practices, cost based, feed-in tariff program of sufficient project size up to 12,000 megawatts. We think all of these other discussions, in terms of meeting the interconnection challenges, the technical challenges, all of these things are great. They’re required. We need to make progress on them. But we still won’t realize that goal if there’s not a financing mechanism in place.

And then finally, of course, one of the biggest objections traditionally to feed-in tariffs is that they’ll pay too high of a price, there will be a ratepayer impact. The good news, of course, is the dramatic cost in solar prices today and even if a new feed-in tariff program process were to started today to be put in place it would probably be two years before the first contract was signed under that program. By that time the prices will be even lower, probably close to grid parity. We really believe that a feed-in tariff program could offer, for a lower price for the energy, than would be required through the Ram program.

And then a couple other problems with the Ram program is it still produces winners and losers. Some people win the bids, others don’t. And that’s a waste of resources to society and preparing those. And also, it effectively excludes smaller generators. We’ve got to have a feed-in tariff program to allow smaller generators, particularly, we’ve had a lot of discussion and presentations on EJ communities, RESCO communities, they’re to some extend excluded under the currently programs.

So anyway, I’d like to encourage you to work with the agencies and the government to try and get a good feed-in tariff program in place. Thank you.

CHAIRMAN WEISENMILLER: Thank you. I was going to say obviously this Commission has looked into the feed-in tariff and been a very strong supporter which we can trace back to my colleague John Geesman when he was here and the 2005 IEPR and certainly the last IEPR produced the KEMA study, so we've taken a very strong position. Obviously, one of my intentions in my IEPR is not to reopen or not to go through that whole record again but certainly to take comments on it. I would note that one of the—this whole renewable market, the developers are much more international in character and you have like an AES whether to go here or China or Europe, where to put or limit their PV cells or wind stuff and at the same time, the Chinese government realizing instead of buying (indiscernible) they're rather buy infrastructure here and invest in infrastructure. What the foreign countries tend to say is that the attraction of going to Europe for the feed-in tariff is it's much easier to monetize things than here where we use the tax equity approach. And somehow they have to find an entity here that has the appetite for using those tax benefits as a way to monetizing the assets. So it's a much more complicated for a Chinese or a Spanish company coming into the U.S. than a feed-in tariff would be in terms of monetizing the value of those investments.

MR. PINGLE: Thank you.

MS. KOROSEC: All right. I have one last question on the WebEx. Anthony, you had a question earlier. Your line is open if you'd like to ask it. All right, I think Anthony has left the building.

All right. Is there anyone else in the room that would like to make any comment? All right, if not, I think we are done for the day. Commissioner, thank you.

CHAIRMAN WEISENMILLER: Again, I'd like to thank everyone for their participation, particularly the last panel and certainly would thank those that are on the lines for following us as long as they did. Anyway, there will be more events. We're looking at an event in June that's going to deal more with some of the DG on the distribution issues again.

Yes, would you repeat the comment due date for people? And for those of you who have not had a chance to comment, certainly written comments would be appreciated.

MS. KOROSEC: Comment due date, I believe, is May 31. I'm sorry I don't have my notes in front of me so—

CHAIRMAN WEISENMILLER: No, no. Earlier is better.

MS. KOROSEC: The date is in the notice, it's probably the 23rd. It's the 23rd. Pardon me that was an error.

CHAIRMAN WEISENMILLER: We think that it's the 23rd.

MS. KOROSEC: Yes, we just looked at the notice. It is the 23rd.

CHAIRMAN WEISENMILLER: Thanks. We're adjourned.

[Meeting is adjourned at 5:52 p.m.]