JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2008	)	Docket No.
Integrated Energy Policy Report	)	08-IEP-1G
Update and the 2009 Integrated	)	
Energy Policy Report	)	
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, SEPTEMBER 3, 2008

1:00 P.M.

ORIGINAL

Reported by:
John Cota
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, Integrated Energy Policy Report Committee

ADVISORS PRESENT

Panama Bartholomy

Kristy Chew

Laurie Ten Hope

Tim Tutt

STAFF and CONTRACTORS PRESENT

Suzanne Korosec

Rachel MacDonald

Donna Parrow

ALSO PRESENT

Philip Sheehy, PhD, TIAX LLC

Michael F. Lawrence, Jack Faucett Associates

Mohamed M. El-Gasseir, PhD, RUMLA, Inc.

Sachu Constantine, California Public Utilities Commission

Manuel Alvarez, Southern California Edison

Eric R. Wong, Cummins Power Generation and California Clean Distributed Generation Coalition

Polly Shaw, Suntech

Susan M. Buller, Pacific Gas and Electric Company

Wade McCartney, California Public Utilities Commission

Chuck Solt, California On-Site Generation

Peter Evans, New Power Technologies (via telephone)

I N D E X

P R O C E E D I N G S

1:07 p.m.

PRESIDING MEMBER BYRON: Good afternoon, everyone. Welcome to a Joint Committee Workshop of the Integrated Energy Policy Report Committee and the Renewables Committee.

I am Commissioner Byron, Chair of the Integrated Energy Policy Report Committee. And with me are my advisors, Laurie Ten Hope and Kristy Chew. I think we have two more advisors that will be joining us. And I am so pleased to see that someone has moved the clock back a couple of minutes so that at least it looks like we are starting on time. Thank you all for being here this afternoon. Some of the advisors aren't aware that we shifted the clock.

I am unfortunately only going to be able to join you for about the first hour and I believe my staff has to scurry off to different meetings as well. And I apologize for that because I am very interested in this subject.

This is one of the main topics of our Update IEPR report that we will be putting out in the next month or two. I am just being vague about it because I don't know the exact schedule.

But there is a very precise schedule and they are working very hard to finish this report.

I had the opportunity to meet with the staff and a contractor this morning and reviewed some of the materials. And I have to say in all honesty I found it very interesting and I really regret not being able to be here to hear all the presentations. So please accept my apology in that regard.

But this work is extremely important and it is required by legislation. The staff will go over it here shortly. And I am very encouraged by some of the results.

But we have also had some difficulty getting the data for this in a timely manner and maybe we will discuss that a little bit. But this is, as I said, required by legislation and that enables us the rights to go after all the data that we need in order to do it.

We are very appreciative of the cooperation we have received from the investor-owned utilities in order to get this data and I am hopeful that we will complete this on time.

So having said that I will just turn to see if Tim Tutt, who I failed to introduce, Chairman Pfannenstiel's advisor who just joined us, if he has any other remarks he would like to say.

ADVISOR TUTT: I have none.

PRESIDING MEMBER BYRON: Okay, Ms. Korosec.

MS. KOROSEC: All right, I'll just do a few, quick housekeeping items. For those of you who have not been in the building before, the restrooms are out the double doors and to your left. There is a snack room on the second floor of the atrium under the white awning. And if there is an emergency and we need to evacuate the building please follow the staff out the door to the park across the street. And we will gather there and wait for the all-clear signal.

Today's workshop is being webcast. And for those of you listening on the webcast who may wish to speak during the public comment period the number is 888-566-5914 and the passcode is IEPR. So with that I will turn it over to the project manager for this evaluation, Rachel MacDonald.

MS. MacDONALD: Good afternoon. Thank you, Commissioner Byron, for opening and thank you, everyone, for attending.

Today's workshop is a half-day workshop and we are going to be reviewing the Self-Generation Incentive Program Cost Benefit Analysis that was legislatively mandated by Assembly Bill 2778. I'm sure everyone is familiar with it, given the content we have put out.

But basically TIAX was the contractor that conducted this work. They will go into more detail during their presentation. This work is required by the Legislature and we are to also coordinate with the CPUC and the ARB. And Sachu Constantine from the CPUC is present as well Tom Pomales from ARB.

We are looking at doing this cost benefit work on air pollution, efficiency and the T&D system impacts. That is what is required and what is in the actual language of the bill. And we have kind of extended that as well so that it includes some environmental work, macroeconomics and extended T&D work.

A little bit about the schedule and dates. I'm sure everyone is familiar with the fact that the work has been anticipated and we did experience some delays with receiving the data. A lot of -- Our contractors will go into that as they progress. But a lot of the work is actually from what was put out with the workshop notices. So what you, what is going to be discussed today has been evolving like minute by minute because this data was recently received and it literally has results coming in constantly.

And we have our workshop today, the 3rd. Written comments. I apologize for the short turnaround time but we do have written comments due to the Commission by September 5. We will have the full Draft report with more results on the 18th available for circulation with the IEPR, with the Draft IEPR.

The IEPR workshop, including our chapter, and the contribution for 2778. That requirement will be at the IEPR workshop on October 9. Comments from that IEPR workshop are due the 16th. The actual final report for this work, for TIAX's work, is going to be done by the end of October. And then we will be adopting it at a Business Meeting, formally, in November. So we do anticipate meeting that November 1 deadline.

A little bit about our structure today. Again I thank everyone for attending. And we are going to go ahead and start off the presenting with Philip Sheehy from TIAX, who is the main contractor doing this work.

And I just -- You already have the agenda but I just wanted to let everyone know that I want to structure it that we present. I know there's going to be a lot of questions because a lot of material that is covered here today is going to have even more detail during the discussion. So I would like to respectfully request that, you know, feel free to ask questions while this is going. If it's lengthy discussion we will have a definite question and answer sessions in-between presentations so we can get more comments during that. And then of course after all three presenters we can have more feedback and discussion as well as people calling in on the phones.

And then just as far as contacts. There's the Commission Docket address. And then my contact information if anybody has any questions for me about this work the contract or the IEPR, as far as our contributions to the IEPR for AB 2778.

With that being said I'll go ahead and pass this off to Philip Sheehy from TIAX.

DR. SHEEHY: Thank you, Rachel. Thank you, Commissioner Byron. Thanks everybody for coming today. My name is Philip Sheehy, I'm from TIAX. We are the prime contractor on this. I am going to give an overview here. Can everybody hear me okay? Okay.

Like Rachel said, we would like this to be as interactive as possible but we also want to make good use of our time. So if you have substantive questions, hold those to the end, that would be great. But if you have something, some clarification, use your best judgement and you can interrupt me, that's okay. So I'll just get right into it here.

This is the outline of what I am going to talk about. I'll go for about 30 minutes, just to give you an idea. I'll go for 30 minutes and then I'll hand it over to Mike Lawrence from Jack Faucett Associates and then Mohamed El-Gasseir from RUMLA will talk for -- Each of us are going to shoot for about 30 minutes uninterrupted so if you interrupt it will go a little bit longer.

Oh, and then there will be, there will be time in-between, like Rachel said. Sorry, let me clarify there. So there will be time in-between the presentations. So if you have a question on my presentation you don't have to wait until the very end to ask.

So I will get into a brief overview of SGIP. A little bit of a crash course. It's a couple of slides there.

And then I'll talk about our methodology and approach at TIAX.

Then I'll also kind of give you an idea of the whole project. So I'll do a little bit of both of those.

I'll give you a brief preview of the results, like Rachel said. We're cruising along and these results are coming up now, actually.

And then we will do the presentations and then we will do the questions and comments.

So overview of the project.

So this is the background. This is a quote. This comes from AB 2778. This is the mandate from the Legislature. At the top there.

Our team is TIAX, we are the prime contractors, and we have Jack Faucett and RUMLA and Advent Consulting.

Then quickly on scope. The scope is a cost-benefit analysis of SGIP. So that's important. So we will get into what actually the cost-benefit analysis means and how we have interpreted that and how that comes into play in our study.

And then the dates here at the bottom, that's important. So the program, as you know, goes through 2008. It's going on today. But our results, based on available metering data, are going to go through 2006. And so using installations between 2001 and 2006 and projecting over the lifetime of those technologies. So that's important to know.

So just a quick crash course in SGIP. So I've got a timeline here. So the program starts kind out of AB 970 there on the far left in 2000. It actually becomes SGIP in 2001. There's some incentive level changes basically between 2001 and 2005. Max system size changes, things of that order.

So just a brief overview, incentives are paid out based on the technology up to one megawatt of installed capacity and your maximum installed capacity is five megawatts. It used to be 1.5 megawatts but that was increased in 2005.

At the beginning these technologies

ranged from photovoltaic to fuel cells, microturbines. And we'll get into more of the specifics a little bit later.

But then in, I believe it was 2006 the CSI, the California Solar Initiative was approved. And then as -- That was 2005, I believe. Then as of 2006 or 2007, yes, 2007, sorry, all PV installations were administered through the California Solar Initiative. So there was a shift after the lifetime of our analysis. So you will see a lot of PV in our analysis and we will be analyzing those as part of the program. But moving forward solar is no longer eligible under SGIP. You get other incentives for that.

And the key point here is this 2008 point. AB 2778 comes into effect, which reduces the technologies, or narrows the technologies eligible for SGIP incentives to fuel cells using a renewable resource and wind turbines.

This is an overview by technology again. We were looking at a variety of different things in this program earlier. A lot of different terms and I'll define them as best as I can going along.

Right now we are going to be looking at these by technology so this is the status of SGIP through December 31, 2006. And we have broken this down into photovoltaics, microturbines, gas turbines, internal combustion engines, these run on natural gas or a renewable fuel, fuel cells and wind turbines.

So the second column is the number of installations. We are dealing with nearly 1,000 installations through 2006. The bulk of those are PV.

And then the third column there is fuel. The photovoltaics don't require fuel other than the sun so we are talking about natural gas. So you have a non-renewable fuel or a renewable fuel. So I've separated those out here in the different technologies.

Then installed capacity. So we're looking at about 235 megawatts installed capacity through 2006 for these various technologies.

And then on the far right is the incentive payment, which is paid out by the IOUs. And roughly about $400 million has been spent on the program. Excuse me, $400 million, again through 2006. So there have been changes to that but that's outside of our scope.

And it is important to note here, this

$400 million is matched by private investments of roughly two-and-a-half to one. So you're looking at about $1 billion in private investment matching $400 million in incentive payments.

MR. CONSTANTINE: One question. What status are you using to --

PRESIDING MEMBER BYRON: Excuse me for a second. If you would, please come to the podium. You are welcome to ask questions but we just -- because we are keeping a record. Come on up to the podium. Just introduce yourself and ask your question with the mic with the green light on the microphone. And that way we will be able to record it and those on the phone will also be able to hear us.

MR. CONSTANTINE: Sachu Constantine from the CPUC. I just wanted to know what criteria you are using to count as an installation. Is it in the payment queue or is it fully interconnected and payment is already made?

DR. SHEEHY: Right. In our analysis, so there's -- this is a good question. So there's reserve installations. So you go and you put in your application but you haven't received payment yet. You might not be on-line. So we do these on a case-by-case basis, more or less. So it varies between -- Most of these are on-line systems, this 0905. Most of the ones we are analyzing are on-line systems that are generating power.

MR. CONSTANTINE: Thank you.

DR. SHEEHY: Okay. So there are some that have been installed through 2006 that may have not received a payment, for instance. And in some cases those will be considered in the analysis depending on if there was metering data on them yet. Some of them got in by the, by underneath. But if we have no metering data on them that we decided basically that they are not going to be part of the analysis. That's a good question though.

So this all comes out. This is important to note. This all comes out of the impact evaluation reports that Itron has prepared. Itron is the contractor who has the metering evaluation contract with the utilities to meter this program and evaluate it and they issue yearly reports. So a lot of this information comes from them.

So this is broken out by -- So you can do it by technology. This is done by IOUs. But it's a little bit more nuanced than that because they are actually program administrators per SGIP. So the program administrators are PG&E, Southern California Edison, SoCal Gas. And then the bottom one, CCSE, is the California Center for Sustainable Energy. It's a nonprofit group that actually administers SGIP on behalf of the SDG&E customers.

Those are just broken down by installed capacity. You can see that PG&E has the lion's share of installed capacity as of 2006.

So let's get into the reports. Now you have a good overview, let's see what we're dealing with. The size of these systems, incentive payments. You have an idea of the magnitude of what we are dealing with here. So we'll get into methodology and approach.

The cost-benefit analysis. What are we doing here? Economists love to -- I find them confusing sometimes. Unfortunately I am not an economist but I'll try to make this as clear as possible because defining what is a cost and what's a benefit can be tricky and it's important.

So first of all we want to define scope. That's easy. We're looking at SGIP.

So then we want to define standing. So this becomes an issue of whose benefits are they, whose costs are they, and what's really counted in your study. What perspective are you looking at this from? In our approach we are looking at society. Not just the ratepayer or the participant or the non-ratepayer or the non-participant, excuse me. We are looking at a society-based test. So who is benefiting here and who is incurring the costs.

Then straightforward again. Identify the benefits and costs. And here the most important thing is to make sure that we are not double counting. And then also when you identify the benefits and costs we really want to make sure that we identify the ones that we can do really well and the ones that we might not be able to quantify. We want to be straightforward about that.

So then we want to go forward. Define our approach to quantify both benefits and costs.

And then lastly, we want to decide the time horizon. So for most of these technologies we are assuming a 30 year lifetime. That's reasonable based on their performance in the past.

So this is, and this is a subtle difference but it is important to point out I think that in this cost-benefit analysis -- typically you conduct a cost-benefit analysis before a program takes place. You come in and you analyze a potential program, compare it to some alternatives. And depending on the costs and benefits you decide which approach to go with.

In this case we are actually doing a cost-benefit analysis of a project that is in place. We have data. So in principle you'd like to do a cost-benefit analysis before a program starts but that's not the case here. But it actually gives us the advantage that we have data. We have metering data which is, again, SGIP is a unique program so we're dealing with a unique opportunity to study self-generation in a way that other people have been unable to in the past.

And again this is different than in -- I make this final point here just because it is different than what is used by the PUC to evaluate the cost effectiveness of demand side management programs as defined by the standard practice manual. We borrow guidelines from that but we are not necessarily bound by all the guidelines of the standard practice manual. So that's an important distinction also. So this is just an overall approach.

So this is a very simplified breakdown of the costs and benefits. You have installed costs, ongoing operation and maintenance, administration of the program. And then we are metering and evaluating this so that's another cost.

And these benefits I left vague because I want, I am going to define the environmental benefits. So this is a good breakout of how our team is operating. So TIAX is going through and we are out looking at the technical performance of these installations and determining the environmental benefits. And the rest of my talk is going to be about that.

The macroeconomic benefits, which JFA is looking at, they are going to elaborate and elucidate those in their talk.

And then Mohamed is going to, from RUMLA, is going to talk more about the grid benefits.

So this is, again, this is just to give you an outline. We're going to get into these in more detail so we can argue over the benefits a little later as we get into more detail.

So where are we getting our data from? An issue for -- You know, there's program administrators who are different than the IOUs at times. That's why I have it there. They provide basic SGIP facility data. So this is, again, you heard about a hold-up. And this was basically a function of a non-disclosure agreement. We are getting private customer data here so the utilities wanted to ensure that the customers, they were protected through a non-disclosure agreement. Not only through the Energy Commission and the PUC but also with TIAX and our subcontractors. So that was just to touch on the delay. I didn't want to make it sound like entirely it was non-compliance with data requests.

PRESIDING MEMBER BYRON: In fact, nor did I want my comments to sound that way. In fact in particular I would like to thank San Diego Gas and Electric, who I understand was very forthcoming with the data; is that correct?

DR. SHEEHY: Okay. Yes. Do you want me to elaborate on this?

PRESIDING MEMBER BYRON: No.

DR. SHEEHY: No, okay.

(Laughter)

PRESIDING MEMBER BYRON: And Southern California Edison. In fact, Manuel Alvarez here was very instrumental in helping us get that shaken loose, if you will.

DR. SHEEHY: Yes.

PRESIDING MEMBER BYRON: So no, we don't need to go into a great deal of detail though, on this. But I am interested, will you be getting everything you need? Do you have everything you need as of, I believe you said about a week from now?

DR. SHEEHY: I believe so. By this Friday, yes, has been the deadline that's been told to, informed, that we have been informed of. So that's not our imposed deadline, that's from the IOUs. That everything we want we'll get by Friday. And Mohamed can tell you more about that. He has been in direct contact with distribution engineers at the ground level to get what we need.

PRESIDING MEMBER BYRON: Okay, thank you.

DR. SHEEHY: Okay, back to the data. So basic SGIP facility data. What are we looking at?

We are looking at the technology, we are looking at the fuel, installed capacity, where these things are. This becomes important. Installed costs and incentive payment.

So then the second information, the project cost breakdown worksheets. Mike Lawrence from JFA will talk about how we used those. These are worksheets that the participants provide that break down their costs of the installation to determine whether or not a cost is eligible or not. We have actually found that as a resource, as an input to the model that JFA is going to be using and he will describe in more detail.

Then the interconnection data. This has been, this is the most unusual request that the utilities have gotten. They haven't had this level of detail requested before in relation to SGIP so this is the, this is what requires really getting into the detail of the grid. It has to do with substation, voltage of the nearest interconnection line. This is really what Mohamed has been looking at.

And the other source is Itron who has done all the metering. And they have done three different types of metering, electrical net generator output, fuel use and waste heat recovery. So again, this is a unique program in that this data, these data are available, which haven't been collected on such a large scale before.

And then also the published impact evaluation reports. I have had many conversations with George Simons at Itron. They've helped us out as much as possible whenever we have a request.

Okay, so how are we looking at the technical performance of these technologies is a good question. So I know what you're thinking. So you're thinking, all right, you have an installation that was installed in 2003, you've got data through 2006, and you're going to tell me the benefits through 2030. Okay, so do the quick math, there's 24 years there of no data. So really we have to use what data we have.

And then very simply, when we don't have data we have to be smart. So we have to look at, so actually I can give you a couple of examples of what that means to be smart. So for PV, for instance. PV is a locational-dependant, self-generation technology. All the red dots you see there, this is SDG&E's range. All the red dots there are PV installations. All the yellow dots there are the suns or weather stations.

We don't have data for one system, we go to a neighboring system and we look at their average capacity factors and we look at solar radiation data. And we can fill in gaps. And then we use an average of 2003 to 2006 projected into the future. These things are pretty reliable in their performance so that's actually a good estimate.

So again this is locationally-dependant so, you know, you have pluses. And you can see down there near San Diego there's quite a few of these that neighbor each other. Again, a handful up there near Carlsbad. So there's generally good enough data coverage in most of these areas where even though you don't have a metered point at a particular hour you can actually make a pretty good estimate as to what that PV system was generating based on neighboring installations and solar radiation data.

Okay, so not everything is locationally-dependant. Internal combustion engines, microturbines, fuel cells and gas turbines, these aren't, these don't care about the sun so they are not locationally-dependant. But what we do is we look at all these systems. And there's a lot of similarities between these. There's only a handful of manufacturers of these things and we assume that people are operating these to their greatest benefit.

So whenever we have data we assume that all the installations that don't have data are operating similarly to the ones that we do have data for. I mean, this is, again, there are assumptions in there but by and large this is, this is the best approach that you can, that you can employ. And it's an average case scenario. I'm sure that there is a better case scenario in which you are assuming that the ones that you don't have data for are operating better. But that's necessarily fair in this analysis, okay. So that's just regarding data gaps.

Okay. So now before we get into any results let's set some ground rules here in the analysis. So now we are going to be talking specifically about environmental benefits here. This is what TIAX is looking at here.

So here when we are talking about

environmental benefits we are determining them as avoided damage costs, not avoided control costs. So it costs me a different dollar per ton to prevent NOx from being emitted than it does to clean up a ton of NOx when it was emitted, okay. So we are looking at the damage costs. What is actually, what damage is being incurred by society by a ton of this being emitted. This is a standard approach recommended by the EPA Office of Air Quality.

And there are three types of damages that we look at and most of them are direct damages to humans. And we'll get into this in a little bit. But most of these are air quality issues. And then you have indirect damages, either through ecosystem or non-living systems. So if you have buildings that are decaying and you have to fix them it's a minor cost. So these one, two, three go in order of magnitude, you could also say.

So then secondly we're doing a benefits transfer. So whenever you do --- So what that means is that there is an existing study that values the NOx at a certain dollar per ton. But that dollar per ton is based on a certain exposure. The dollar per to is based on the health damages to humans. So what you do is you say, you have to correlate the existing research with the exposure that happened in California. So the damages cost vary depending on population density. They vary depending on dispersion rates. These are all things that we look at.

So benefits transfer. If you just take a value and blindly apply it you can get in trouble. But this is something that TIAX, something that we're good at. So these are potential -- we are aware of the potential pitfalls and where the uncertainties arrive at this and we can minimize those in any sort of benefits transfer.

So then just for baseline purposes everything is going to be in 2006 dollars.

All right, discounting. We had some questions about this previously. So we are going to discount things like operations and maintenance at seven percent. Anything that's prior to investment we discount it seven percent. This is from the Office of Management and Budget, we didn't make this up.

Now for environmental benefits it is

different than a private investment. There's plenty of literature out there that suggests that when discounting environmental benefits the standard rate is basically valuing environmental quality, higher now than generations in the future. And with increased profit sustainability at the Energy Commission and throughout California it is actually important that we account for this.

So we are looking at a declining discount rate. Which really doesn't decline that much over a 30 year time scale. These things change more on a 50 to 100 year time scale when you're looking across the entire lifetime of, for instance, the CO2. But we are starting at 3.5 percent. Again, there is literature on this and this will be cited in our report.

I just have two quotes up there. There are people who disagree with a lower discount rate for environmental benefits. These are two economists that I like their description. Pigou referred to exponential discounting on future welfare as defective telescopic faculty. I thought that was very succinct.

And Weitzman says, this sounds Rumsefledian to me but: "To think about the distant future in terms of standard discounting is to have an uneasy intuitive feeling that something is wrong, somewhere."

And again, like I said, we are really trying to stay in line with these issues of sustainability. So we think that this is an important distinction between discounting private investment and the environmental benefits.

Okay, so when you determine an environmental benefit you have to define a baseline. So in this case centralized power generation. We are looking at self-generation so we want to look at the centralized power generation.

And there were -- Some of you, or hopefully many of you read the attachment accompanying this workshop and there was an error in there that has since been corrected. And so specifically we are going to be looking at marginal power generation. Not the average. We want to look at the last kilowatt hour of power generated, which in California is defined as natural gas-fired combined cycle combustion turbine. This is pretty clean stuff.

Okay. So then in terms of -- So we had

two different types of benefits here. We have an air quality benefit and we have a climate change benefit. So air quality is a local and regional issue, climate change is a global problem. So in terms of greenhouse gas emissions we look at the life cycle emissions of the installations, of the self-generation installations as compared to centralized power generation. So there's a CO2 equivalence.

And then criteria pollutants. And this is work that TIAX has done in the past for AB 1007, the State Alternative Fuels Plan, excuse me. Looking at the life cycle emissions of fuels in electricity and as a transportation fuel also so this applies to this case.

So criteria pollutants. What we do is we look at them solely, the criteria pollutants that are emitted in California. And we have also accounted for pollutant offsets. So whenever you put in new generation you have to buy NOx or PM credits to offset those. So we've actually accounted for those in there.

So what are we looking at? So here's our emission factors. So you have our pollutants. So we have air quality pollutants on the top, volatile organic compounds, NOx, carbon monoxide, SOx, PM2.5. So VOC and NOx are both ozone precursors. NOx is doubly dangerous because it's a precursor to particulate matter formation.

CO is kind of a cleanser in the atmosphere also but we are also -- actually putting a dollar value on that is tricky so we're actually not going to do CO. I just wanted to show the emission factors.

And SOx, actually California regulates SOx emissions extremely well so the emissions actually from marginal power generation in California are zero. You see there in the third column.

PRESIDING MEMBER BYRON: Mr. Sheehy, just a clarification if you would.

DR. SHEEHY: Yes.

PRESIDING MEMBER BYRON: Are you going to be reporting out CO and not including it in the economics or will it be omitted from the report all together?

DR. SHEEHY: We will -- excuse me. We will report the CO benefits on either side, yes.

PRESIDING MEMBER BYRON: Good. I think --

DR. SHEEHY: It just won't necessarily have a monetizing. It's definitely just an issue.

PRESIDING MEMBER BYRON: Understood. Good, thank you.

DR. SHEEHY: Okay. So then, again, PM2.5. So what I did here is on the left I put the total emission factors for marginal power generation in California. Excuse me, total emissions on a life cycle basis, excuse me, on the left. And on the right you see just the emissions in California to account for offsets. So you can see they have dropped dramatically in the order of magnitude sometimes by half. Just to show that we are looking at pretty clean systems. We are comparing to pretty clean systems, which is important to consider.

And then for GHGs we are emitting about 500 grams. So these are all in grams per kilowatt hour.

So then on the far right I've got the dollars per ton. And these are all in 2006 dollars. And all these numbers are coming from the reports at the bottom there. They are about $8,000, almost $9,000 per ton for VOC as a damage cost, which is derived from a report that TIAX has done previously for the Energy Commission and the Air Resources Board on the strategy to reduce petroleum dependance.

So NOx, there are two values there for NOx because the top value is NOx in the gas phase and then the bottom number is NOx as particulate matter. So on balance you are looking at about $23,000 per ton there.

And these are some, there's a linear relationship between NOx emitted and how much goes into the gas -- and how much goes into -- how much becomes particulate matter.

So there is no -- There is a dollar per ton for SOx but because the emissions factors are zero I just decided to forgo.

Now PM2.5 is dangerous. This is what ARB, the Air Resources Board spends a lot of their time trying to reduce particulate matter, for a good reason. The dollar per ton in California is about $650,000 per ton in damages costs. There's a lot of hospitalizations, a lot of morbidity and mortality related to PM2.5 so this is a high value pollutant.

Then at the bottom there the GHGs. That's coming from the IPCC, which is a -- which the IPCC recommends, which is based on a study, a meta-study of 28 published reports and 110 social costs of carbon. So it's about $12 and that's in metric tons. Everything else is in short tons. We just do GHGs in metric tons because that's a little bit more the language of the community.

PRESIDING MEMBER BYRON: Mr. Sheehy, before you leave that slide.

DR. SHEEHY: Yes.

PRESIDING MEMBER BYRON: One quick question. On the PM2.5, for instance, you indicated that was about $650,000.

DR. SHEEHY: Right.

PRESIDING MEMBER BYRON: But yet you have a number up there that has six significant digits.

DR. SHEEHY: Right.

PRESIDING MEMBER BYRON: Could you speak to that a little bit throughout these tables.

DR. SHEEHY: Yes, sure. So in general we -- I mean, this is, again, this is information taken from other reports. And they reported based on -- I mean, there's uncertainties in these so yes. The significant figures in general should be lower. I agree that it should be probably something like 6.4 times 105.

In the final report, though, we'll account for that based on the uncertainties associated with determining each one of these.

PRESIDING MEMBER BYRON: Thank you.

DR. SHEEHY: This is just to get you --

PRESIDING MEMBER BYRON: It just implies a level of accuracy that may not be --

DR. SHEEHY: That isn't there. You're right, you're right, that is absolutely correct.

PRESIDING MEMBER BYRON: All right, thank you.

DR. SHEEHY: Although the $12 per ton is pretty accurate from what I understand, per metric ton.

PRESIDING MEMBER BYRON: I'll take that.

DR. SHEEHY: Okay.

PRESIDING MEMBER BYRON: That's two significant digits, we'll take that one.

DR. SHEEHY: Yes, okay, thank you. Okay, so let's give a preview of results. What are you looking at in terms of environmental benefits here. So let's start off with microturbines. Oh, I'm lying, I was going to start with PV. Sorry, got ahead of myself.

So let's look at just SDG&E. And this is -- I picked SDG&E because it's a function of where we are at in the analysis, not because of anything special about SDG&E. SDG&E happens to have the best data coverage for PV installation so we had -- this is also the most accurate number because there's the least amount of filling in gaps of data. If that makes -- I hope that's clear.

So we are looking at about 90 installations, 92. We are looking at 92 installations, not about. Ninety-two, that's significant. Installed capacity is 12 megawatts. Megawatt hours generated. And this is over the lifetime of 92 installations, installed capacity 12 megawatts. So the total megawatt hours generated over the lifetime of these 92 installations is about 380,000 megawatt hours.

So what we need to do is take those emission factors and we turn them into emission reductions. PV is very straightforward because there are no emissions associated with PV. So we just look at what it would take to generate that same amount of capacity or that same amount of energy on the grid using a natural gas combined cycle turbine.

So you can see over 30 years here we are looking at a marginal increase -- marginal emission reductions in VOC and NOx. So like I said, the centralized grid is pretty clean when it comes to VOC and NOx and PM2.5, mainly because of these offsets that they have to provide. But this is important to note.

And then GHGs we're looking at about 191,000 tons over the span of 30 years. Just to give you -- These are metric tons again. All the GHGs, remember, are metric tons. And just to give you, to remind you of what California is emitting as of 2005, it was about 500 million metric tons of GHGs on an annual basis. So we're talking about 191, we're talking about .191 million metric tons. Okay? So it's small.

So that's just, that's just PV and just for SDG&E. And this is just the result. Then we have the monetized value on the right based on declining discount rates, et cetera.

Okay, so now for microturbines. Jeff, my colleague in the audience is doing the analysis on microturbines and it happens that he is a little bit ahead of me. So Jeff has done both

SDG&E, and on the right you can see this is for all microturbines. So we're looking at about 17 megawatts across the entire, everybody. All microturbines there are about 17 megawatts. SDG&E is about 1.6 megawatts. Okay.

So what we do is we look at the data for these installations and estimate -- Again with regard to significant figures I defer to Commissioner Byron's point that these are probably closer to two to three significant figures rather than eight in some cases. I apologize for that.

So we are looking at the megawatt hours generated in SDG&E and off. That's the first category. And then we are looking at how much natural gas these microturbines use. And then we want to look at what are the megawatt hours of electricity that was saved through combined heat and power applications. Again, we do this on a megawatt hour and a million metric BTUs. Yes, a million metric BTUs.

So then in terms of emissions we have those again. We have the air quality on the left, the VOC, NOx, PM2.5 and GHGs on the right. And note that this table is slightly different and that these are actually the emissions compared to the grid. And a positive number means that you have actually emitted more than the grid, and the negative number means you have actually emitted less than the grid would have to generate the same capacity.

So you can see here -- And again, this is over a 30 year lifetime so this is about 2035. Over 30 years we have emitted through all the microturbines about 55 tons of VOC. Which is on an annual basis one ton of VOC. From one to two tons per year on an annual basis is actually very low. So this is more or less zero for VOC, NOX and PM2.5.

And again you get a slight GHG benefit on the SDG&E category. Then you can see on the right one of the first -- one of the first questions we should ask is, on the total if you look at across all utilities the GHGs are actually 100,000 increase. But then in SDG&E's category you've got a -10,000. How is that? So SDG&E happens to be a high concentration of microturbines that have been installed with a renewable resource so they actually have carbon credit, a carbon benefit. Whereas on the balance you are actually looking at a slight dis-benefit across all microturbines.

These are also preliminary numbers so these are subject to change also. So that's just a -- This is what our results are going to be looking like. We're going to do them by, we're going to look at them by technology. We're going to break the technologies up in terms of renewable resources and non-renewable resources where appropriate. And we are going to also do this by utility. Again, broken out by utility and by technology really for comparative purposes.

MR. ALVAREZ: I have a question. I guess it wasn't clear.

PRESIDING MEMBER BYRON: Mr. Alvarez, I think you have to identify yourself.

MR. ALVAREZ: Manuel Alvarez, Southern California Edison.

PRESIDING MEMBER BYRON: Thank you.

MR. ALVAREZ: When you measured the production of the particular project did you just assume that that production was offset by the system, by the entire grid?

DR. SHEEHY: Say it again?

MR. ALVAREZ: For example, you had San Diego's production numbers for the PVs.

DR. SHEEHY: Right.

MR. ALVAREZ: It's easier for me to see it on the PV chart.

DR. SHEEHY: Okay, I can go back there.

MR. ALVAREZ: And so you have the 378 megawatt hours.

DR. SHEEHY: Right.

MR. ALVAREZ: Did you just assume that that 378 megawatt hours were reduced from the San Diego grid?

DR. SHEEHY: No.

MR. ALVAREZ: Okay. So how do you track that back?

DR. SHEEHY: So you generated 380,000 megawatt hours, right?

MR. ALVAREZ: Right.

DR. SHEEHY: So you assume that otherwise that would have been, that 380,000 megawatt hours would have been generated by marginal power generation on the grid.

MR. ALVAREZ: Okay, so you just transferred it for a one-for-one reduction.

DR. SHEEHY: No, I don't think you, I don't think that's --

MR. ALVAREZ: Okay, then I don't

understand it here.

DR. SHEEHY: It's not a one-for-one reduction. If they didn't have this then it would have been -- The assumption is that if they didn't generate these 380,000 megawatt hours --

MR. ALVAREZ: They would have generated three hundred --

DR. SHEEHY: Eighty-thousand megawatt hours.

MR. ALVAREZ: -- additional from gas.

DR. SHEEHY: From natural gas combined cycle turbines.

MR. ALVAREZ: Okay, so that's just the basic assumption. You didn't go back and do a production run to see what the actual differences were.

DR. SHEEHY: No.

MR. ALVAREZ: No. Okay, thank you.

DR. SHEEHY: Are there any other questions before we hand over the mic? Yes.

MR. WONG: Eric Wong for Cummins and also on behalf of the California Clean DG Coalition. Phil, I want to take you back to Slide 17 where you talk about the marginal power generation. And you have it defined as a natural gas-fired combined cycle combustion turbine.

DR. SHEEHY: Yes, that's correct.

MR. WONG: Did you assume that the SGIP technologies that you defined earlier in the report are matching up in terms of where they are in the load? For example, CHP which operates as a baseload would be compared to baseload. Whereas photovoltaics and wind would be more peaking resources in terms of doing an environmental analysis. We just wanted to know what relationships there are between your margin of power generation versus how they are actually operating.

DR. SHEEHY: So in doing this you just assume that the last kilowatt hour produced on the grid is going to come from natural gas, regardless of the time of day. So you're saying that if you look at peak then you might get some peaker plants on, which are maybe dirtier.

MR. WONG: In terms of the pollution that is coming out of them, correct.

DR. SHEEHY: Right. So those actually would -- I don't know what the effect would be but no, we did not take that into account. So what we did is we assumed that the last kilowatt hour generated by the grid is what you are displacing.

MR. WONG: I want to raise that for you folks to consider and respond to.

DR. EL-GASSEIR: I am going to touch on that.

DR. SHEEHY: Okay.

MR. WONG: This is actually -- I'm going to bring something now because you have kind of an over-arching presentation here but probably it's for Mohamed El-Gasseir. The concept of the grid operating, the entire power system as a generation and transmission distribution operating with and without SGIP resources. I don't think that's been captured here, unless Mohamed says that it is. But you change the operating efficiencies of the system. You can affect transmission distribution. You can affect congestion. You can affect how much it costs to operate the system with and without SGIP.

DR. SHEEHY: Yes, that will be addressed. But, I mean, in terms of environmental performance, that really shouldn't, it shouldn't change the environmental performance. But yes, that is a question for Mohamed in terms of Mohamed for his presentation, yes.

PRESIDING MEMBER BYRON: Mr. Wong, do you mean in terms of locational benefits or changing the dispatch order or merit order of efficiency?

MR. WONG: Actually yes, that would include those.

PRESIDING MEMBER BYRON: Okay.

MR. WONG: I think one of the things after having worked on Senate Bill 1012, which is the one that was supposed to reinstate technologies to the SGIP, an interesting piece of information for the Legislature would be, what are the overall benefits to the system with and without these technologies. So if you include all those I think there are some definite impacts, plus or minus to the system, with and without these technologies.

DR. SHEEHY: Yes.

MR. WONG: The other thing I would, again, lay on the table at this point, I believe it will be addressed in the upcoming presentations is in your Attachment A the SGIP moving forward.

DR. SHEEHY: Um-hmm.

MR. WONG: You talk about the individual technologies. And one of the things I would have you consider is when you have a combination of these technologies. For example, you could have a combination of combined heat and power renewables and advanced storage technologies all working together to have multiple resources that are dispatched.

DR. SHEEHY: Right.

MR. WONG: To meet multiple loads.

DR. SHEEHY: Right.

MR. WONG: You have one load.

DR. SHEEHY: I agree. There is no indication that those are -- we don't intend those to be mutually exclusive. But yes we can talk about -- we can address the fact that you can combine those.

MR. WONG: I'm sorry. Did you say you are going to include the combination in terms of the thoughts above that?

DR. SHEEHY: Well the thoughts -- that part of the report is actually just identifying the technologies.

MR. WONG: Right.

DR. SHEEHY: There isn't -- It is not in our scope to put in those technologies in the grid to see what the changes are. But yes, we can add that. It is not our intention to say that these technologies are mutually exclusive.

MR. WONG: I think it is not one you can analyze, obviously.

DR. SHEEHY: Right, right. No, I agree with you though that as it stands it looks like we just list the advanced technologies.

MR. WONG: Right.

DR. SHEEHY: But the intention isn't, the implication isn't that they are mutually exclusive. So we can add a paragraph. I mean, it should be clarified with a paragraph.

MR. WONG: Yes. I think conceptually you can do it though.

DR. SHEEHY: Right, I agree.

MR. WONG: All right, thank you.

MS. SHAW: Good afternoon, Polly Shaw with Suntech. We manufacture PV cells and modules. Just two quick clarifying questions. I'm confused about Slide 14. For the PV portion were you using capacity factor across all occasions?

DR. SHEEHY: No. We have data on nearly every installation so we can actually determine an average capacity factor on an hourly basis on previous performance and match it up with solar radiation numbers. And then you can -- If we have -- If your -- Let's say I have a PV panel and you have a PV panel. I'll look at my history and I'll look at your history and then we can -- depending on how close we are, if we are looking at the same solar radiation we can actually -- our capacity factors should correlate.

MS. SHAW: And so you're doing average capacity factor per --

DR. SHEEHY: On an hourly basis and a season basis.

MS. SHAW: Per installation, per county, per installation zip code or?

DR. SHEEHY: By groupings. They are grouped by eye.

MS. SHAW: And grouped by, I'm sorry?

DR. SHEEHY: Visual. Looking at them on the map and seeing which ones are closest.

MS. SHAW: Okay. I might just caution you --

DR. SHEEHY: And weather station.

MS. SHAW: I might caution you to take a look at the NREL installation cells and how they vary per ten kilometers and 40 kilometers and so on if you are doing that grouping by eyes because the capacity factors may change.

And the other thing actually I just wanted to check is, was there consideration of the emergence of trackers?

DR. SHEEHY: We actually did not but there are systems in SGIP that have trackers and average capacity factors. This is a report done by Itron about analyzing PV systems and the benefit of the trackers is marginal at best. You should look at the report, it's not my report.

MS. SHAW: Okay.

DR. SHEEHY: And then also to clarify. You said that the difference between capacity factors can be significant. So can you define significant and on what basis. Are you talking about an hourly basis or a seasonal basis? I guess I am confused. So just to clarify, we are looking at a 30 year average.

MS. SHAW: Okay.

DR. SHEEHY: And so those benefits that you are talking about, unless they are on an hourly basis and a seasonal basis then they are going to average out over 30 years. So that's one of the assumptions.

MS. SHAW: Thank you. It's homework for both of us to go back and take a look at. But I just get a little bit more nervous that you are grouping them by eyeball. Because when the 2007 started and the CSI started, some of the San Diego capacity factors were varying quite a bit depending on where they were in their proximity to the coast or other --

DR. SHEEHY: Okay, I don't want to let you leave without clarifying. So I am not assuming that my capacity factor is dependant on you. I have enough data for PV-A, Installation A --

MS. SHAW: Okay.

DR. SHEEHY: -- to determine my capacity factor based on solar radiation.

MS. SHAW: Okay.

DR. SHEEHY: Or based on your output also. They are all dependant on the same factors. In the geometric models it is all geometry and solar radiation.

MS. SHAW: You clarified my question.

DR. SHEEHY: Okay.

MS. SHAW: Thank you.

MR. WONG: I have one question. Eric

Wong again. Phil, excuse me. I am very interested -- let's see, it's slide number six, the technologies. You said that most of these, the 905 total, that most of them are on-line and that there are some that were installed but the payment was pending so you had to make some assumptions.

DR. SHEEHY: Well, these 905 are actually on-line. Actually if you look at Slide 7 there is a difference there between 948 and 905. That's the difference. I don't know the exact terminology but they have on-line, completed and active systems and I can't break that difference down for you, to be honest, off the top of my head.

MR. WONG: I have not examined the database, the SGIP database. But, for example, could you have a plant that was on-line in say 2004 but was removed and is no longer on-line in 2006? How would you deal with that contingency? Would you shake those out?

DR. SHEEHY: We would know. Yes, we would know if it's active. In the database it's defined as active, withdrawn, off-line, stuff like that. And I am unaware of any installations that have been, that have been started and then taken off so I don't even know if we receive data on ones like that, to be honest. We haven't come across any that we got data for for two years and then the database went empty because it went off-line. We haven't received anything like that.

MR. WONG: So the assumption is that these are operating through the study period.

DR. SHEEHY: Yes, absolutely.

MR. WONG: All right, thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Sheehy. As Mr. Lawrence sets up to present, if I could, I'll just make a few remarks and that way I won't interrupt his presentation. Unfortunately I do need to leave and will leave, will leave our staff workshop in the capable hands of Ms. Korosec and Ms. MacDonald.

You know, since the SGIP was initiated about eight years ago in one form or another, I forget the name. SGIP or Self-Generation Incentive Program I think came along a little bit later. California energy policy has evolved a bit and certainly there's a great deal of focus now on greenhouse gases. So we are certainly interested in looking at incentives in light of what we are trying to accomplish with regard to these, let's say revised, energy policies.

The Air Resources Board, of course, is depending in their scoping plan to a great extent on combined heat and power and self-generation or distributed generation. And the Public Utilities Commission is very interested in always keeping costs down to a minimum.

So we are going to look very carefully at that evolution of policy and how it affects SGIP and make recommendations in that light. And I am certainly looking forward to the contractor reports in that regard as well. I got a bit of a preview looking at your presentations earlier and the meeting this morning was very helpful. And I am sorry that I am going to miss these next couple of presentations.

But I am very encouraged by the expanded look at benefits in this analysis and the impact that that has on the environment and health. I'm sorry, the impact that environment has on health and the kind of benefit calculations that are included in this report as a result of that.

Also I had not seen before the reporting out of matching funds, which I think would be also of a great deal of interest to the Legislature as well to see that indeed private capital is coming into this in a substantial way into the generation market. And so these other locational benefits that are being portrayed here. I am very encouraged by all this.

And again, I apologize I can't stay to hear the remaining presentations but this report is extremely important now and I am very hopeful that you will make some additional recommendations that our Legislature will pay attention to. And maybe we can get some of the previous legislation that didn't make it out this past year back on track for next year. So I will excuse myself and ask you to go ahead. Thank you.

MR. LAWRENCE: Thank you, Commissioner. I'm Mike Lawrence from Jack Faucett Associates. Staff and colleagues, it's a pleasure to be here today to talk about our role in the TIAX project.

Unfortunately we are kind of at the end of the data pipe so I won't be able to give you much in the way of results today. I'll be talking primarily about methodology and procedures and some thoughts that we have compiled so far. We are in the process of getting the data and the information together and into our models, which will be run this week. So very soon we will have some results and be able to talk more concretely about the numbers.

What I will do in the next few minutes is give you a little introduction about what Jack Faucett Associates is doing on the project.

We'll talk a little bit about stakeholder analysis and the way we look at it in the process of this particular benefit cost analysis.

We will talk about the economic impact assessment tools we are using for this analysis, primarily input-output models and primarily the IMPLAN model.

We will show you a little bit of what the results can look like when we go through this kind of analysis.

And then we'll talk a little bit about our progress.

I'll tell you a little bit about what Jack Faucett Associates was asked to do for this particular project, in particular this particular task in this contract. We had a number of assignments.

The first and primary one was to develop a macroeconomic look at the benefits of SGIP generation. It's a little bit of a broad term and we really focused here primarily on employment and income. So it's not a full macroeconomic assessment of the California economy but looking at those particular components that are impacted by investment in this technology, these technologies.

We were asked to identify the kind of data that would be necessary to do this analysis, which we did, and to evaluate that data and determine what information was available from the utilities on this particular issue. And we were provided with a number of cost reports on distributed generation technologies that took place over the 2001-2006 period. So we had a wealth of information for those technologies in those particular areas to work with.

In order to work with the economic data, in order to work with the cost data we had to convert it to data that speaks the same language as the economic model. So part of the process was taking the engineering information and converting that into economic information in order to run these models. And over the next two weeks we will be running the models and analyzing the results and hopefully have all of the results ready for the upcoming reports.

Let's talk a little bit about stakeholder analysis and why that's important in the process here. As Phil said at the beginning, we are talking about societal benefits in total. And in order to get there we have to look at various components of the marketplace and understand how different actors in the marketplace function and how the introduction of distributed technologies affect different actors at different times.

This can be very important, particularly in public policy analysis, because not everyone is treated the same when markets are impacted. There are some winners and there are some losers and one man's benefit may be another man's cost. So that becomes very important in the process.

(Commissioner Byron, Advisor Chew and Advisor Tutt exited the meeting room.)

One of the things we were asked to do is to do a literature review of cost benefit analyses completed in the past on these technologies and related technologies to determine if we had the right set of cost categories and benefit categories for the analysis.

We looked at a lot of different papers, a lot of different work. As most of you in the room know, that has been done over the last five years or so. More than that even, ten years. And one paper sort of became the sort of general guideline from which we worked from and that was Hoff and Margolis, who in 2005 set out to establish a tableau of cost and benefits and stakeholders. So it fit very well with the analysis that we were doing here and it became the sort of starting point for the process that we went through.

We talk about the stakeholders, and you all know who they are. The investors in distributed generation technologies, ratepayers, utilities, industry. And here by industry we mean those industries that are producing the products that are being installed. And local, state and federal governments. All back to that idea of perspective again.

It's a very important concept when we're thinking about benefit cost analysis, you know. A mayor might feel like adding new jobs to his community is a real benefit. But when the governor of the state looks across the state he might not see those jobs as benefits because he is merely watching the jobs move from one community to another. So perspective becomes very important when you add these numbers up.

This is the first of two pages of this table. It's a little tough to read but I'll sort of walk you through it a little bit. The handouts are in black and white and the shading doesn't do justice to some of these numbers but let me tell you sort of what they are.

The green are categories across that were identified in previous CEC studies and Itron studies so these are categories of cost and benefits.

There are additional categories in blue, which don't show up on the first page, you'll see them on the second page, which were added by TIAX and JFA and RUMLA in our proposal.

And finally some additional impacts were identified in the literature reviews.

And these are -- The idea here is you

look across the page. Across the top you have the various stakeholders. And the pluses and minuses suggest the costs and benefits. Minuses generally are costs incurred by that particular stakeholder, pluses being a benefit. And always one of the issues that economists face in doing this kind of process, sometimes you have negative benefits and you have to decide whether a negative benefit is a cost or a benefit. Some of that comes out in here.

This tableau allows us to sort of think about each one of these categories individually. And when we go to the final presentation this morning, this afternoon, you will hear a lot more detail about the utility cost and benefits and how the utility operations will change as a result, may change as a result of these technologies being in place.

If you look down the left hand column here, you know, some things are pretty obvious. The equipment for distributed generation technologies, the investor is paying for that, it is a cost to the investor. There is somebody who is producing that equipment so it is a benefit to that particular component of industry, the producers of the cells, the producers of materials that go into the cell.

Installation again. The investor is paying for it. Somebody is installing and getting paid for that so there's some jobs associated with it.

Sales taxes paid on that equipment are a benefit to the state, maybe a benefit to a county or even local governments in some cases.

Operating and maintenance costs. These are all the costs that a distributed generator is facing. And, you know, someone is being paid that money. And so we want to capture in this process all of these costs and benefits and sort of put them in the right boxes as we go through the benefit cost analysis.

As we look down the page, you know, we talk about the various components. The electric utility bill, for example, is changing. It is changing for the distributed generator since he is not paying the utility anymore. It is changing for all ratepayers because they face a different rate as a result of this technology being in place and the incentives provided.

So all these need to be taken into

account as we go through the mathematics of the benefit cost analysis to get them in the right boxes for the right people. And to make sure that they are not double counted because that is a fairly common problem in a benefit cost analysis, that benefits will show up in a couple of different places, sometimes masked in various kinds of price effects and changes in marketplaces.

Let's take a look at the second page. On the second page we talk about areas which -- continue the ones from the first page but now focus a little bit more on some of the reasons that Jack Faucett Associates was asked to participate in this project.

There is a focus here on job creation. What kind of opportunities are provided within the state of California. And maybe some of those jobs are not in California, they might be elsewhere. How many are there? What industries do they occur in? Do they occur in the state or do they occur outside the state? Is there an opportunity to bring these industries into the state for further benefits in the future? So somehow we wanted to account for all of these various pluses and minuses on this tableau. And as I said, in the final presentation you will see even a lot more detail when we talk about the utility operations side.

Let's talk a little bit about the economic impact assessment. There are a variety of different kinds of impacts when a marketplace is affected in some way. Some of those are direct, and that's the particular investments that are made to put a particular technology in place. Some of them are indirect as a result of that investment that ripple through the economy. And some of them are induced because you change incomes and different actors within the economy have opportunities to spend these other earnings and they ripple through the economy.

Part of the process here is to establish a baseline and an option. Basically all impact analysis functions like this we have to start with a baseline. Say, what is the -- what does the market look like today in some non-project or without project condition. And then we come back and ask, well if we put these projects in place how will the economy change.

The whole run of the economy with these

technologies in place is what we call the impact. The difference between the baseline and the change can be the benefits when we look at how this power would have been generated otherwise, how it would have affected the economy. And how the power is generated and how the various actors in the economy function under the alternative generation scenario.

So the process here is to try to pull these pieces together, understand the impacts, where they occur within the economy, and understand how they are different, whether we have distributed generation technologies or not. And those differences then can be identified as the potential benefits of the program or part of the potential benefits of the program.

Fortunately there's a tool to do this called input-output models. They have been around for a good long while. In fact Wassily Leontief won the first Nobel Prize in economics for creating inter-industry economics and input-output models. So it's a well-rounded process. It has quite a few uses. And it is very beneficial for the economics profession to be able to take this tool and apply it in a variety of ways.

It also has limitations. There are other kinds of models that do some of these things. Input-output models are very data-intensive. They have a tremendous amount of information about the economy. On the other hand some of the alternative models require even more data. And when they require more data the models become more and more aggregated because you can't deal with that much data and we end up with less information in some cases.

We will be using a model called IMPLAN, which is an input-output model with a great amount of sector detail and geographic detail.

I'll tell you a little bit about IMPLAN. IMPLAN was developed by the US Department of Agriculture's Forest Service in the early '90s. It was later transferred, privatized, moving it to a private sector organization to allow it to expand and be invested in by a number of folks.

The input-output model, the IMPLAN input-output model is very detailed. It's got 509 total economic sectors. That is a very large model. Lots of information in it. It allows you to get a lot of detail on the economic impacts, job creation, tax revenues, change in household incomes. There's a lot of information that can be used to understand how a particular set of investments are going to affect the economy.

It also has a lot of geography. The IMPLAN model can produce individual models by county or aggregations of counties. So you can have a portion of the state or you can have the whole state or a group of states and you can look at them in that way. In this way we are looking at the state as a whole and we are looking at each of the technologies, individually and collectively.

One of the first steps in the process is to convert the information that has been provided by the utilities, which is the costs of the individual technologies as they were put in place. And in economics-speak it is what we call purchaser prices. So that's what the installer paid for a particular piece of equipment or paid for the installation process.

Unfortunately the models operate in what we call producer prices. So that's the price of the technology or the good at the plane gate. So you have to go through a process of converting the purchaser price data to producer price data.

The difference basically is what we call margins. It's the wholesale and retail margins, the cost of transportation. So we have to sort of break these out into the various pieces in order to get the model to run. And that is basically what we have been doing for the last few weeks is that process. And we are at the point now we are just about ready to run the model.

This process includes -- Let me go to the next slide. Again I apologize for the slide. I know you can't read it on your handout. You may be able to read a little bit up here. The idea here is that there are a number of categories that are provided by the utilities in both eligible and ineligible costs.

That's something worth addressing for just a second. What we are talking about here is not whether the costs are eligible or ineligible for the SGIP program. We are interested in all of the costs that have been expended. Because all of those expenditures affect the economy and we want to measure them all.

So we have a variety of categories of costs. In this case, in this list we've got fuel costs first there, equipment costs, electricity storage devices, thermal load costs and other cost categories. And what we have to do is put them into industrial categories, which is the second column. And those industrial categories are then converted into IMPLAN categories, which are very similar to industrial categories. Sometimes they are combinations of those, which allows us to run the models.

So we get all this data from the various installations that Philip was just talking about. All the cost detail and what it costs to put them in place. And we convert those into industry codes and then finally into the IMPLAN model codes.

Now these are used then to produce a benefit cost analysis. And this is a placeholder we put in here because we thought by the time we'd do this we'd have some data to show you. This was actually a dam project in Kentucky. The same kind of issues though. Here is the technology put in place. They have a lot of options in this particular case. Do they build a new dam? Do they repair the existing dam? Do they do other things that would bring water into this particular region?

And you can display a variety of different benefit cost analysis ratios, which allows you to look at the comparison between different alternatives. And within a couple of weeks these numbers will be for the technologies, the distributed generation technologies that we are talking about today.

So we have talked about what we have done so far. We have collected a lot of information. The utilities have provided a lot of information. And we have converted that installed cost information into economic categories. We have set the input-output model up for the state of California to accept this data.

The next step in the process is now taking this data for the installations, for the full set of installations over this period and applying it in the model so that we can understand how the impacts, indirect and induced, will flow through the economy. And allow us to add up the total amount of jobs we are talking about, what the change in incomes we are talking about. And also to do the comparison between generating that power without the distributed generation in place and generating the power with distributed generation in place. Or distributed generation that is in place for the 2001 to 2006 period.

So that's where we are. And we have got a busy couple of weeks ahead of us and we are looking forward to it. I can take any questions if anyone has any. If not I'll turn it over to Mohamed.

MR. WONG: I have a question.

MR. LAWRENCE: We have a question.

MS. WHITE: Michael, hi. Eric Wong, Cummins. Assigning IMPLAN sectors. You said that the focus is on employment for the first bullet. Did you consider the self-generation equipment costs, waste heat recovery costs, maintenance contract costs? Is there in one of these categories the inclusion of engineering design, construction and installation costs?

MR. LAWRENCE: Maybe that's a better question for Philip to answer who has analyzed the actual cost sheets. The question is, where do the engineering design costs fit in the cost sheets?

DR. SHEEHY: That's a good question. Do I need to speak into the mic? Okay.

From what I understand there's a general -- So I had a chance to go over some of these individual worksheets with Mike. Let me pull up one of them, sorry, from the presentation.

So from what I understand, and Mike correct me if I am wrong, but there is a general construction category that distinguishes between -- there's one that's engineering like a consulting category, consulting and engineering like site engineering. And then actually, excuse me, physically building something. So those are two categories from what I understand. They are not listed here. But when we went through them I do remember that there were categories that differentiated between engineering and construction, which in the model are aggregated.

MR. LAWRENCE: These bullets are just a couple of examples. There are about, I don't know, 30, 35 categories of costs that are provided.

DR. SHEEHY: Yes. Yes.

MR. WONG: I would say that from your maybe 35 categories the two high cost items would be the equipment costs --

DR. SHEEHY: Right.

MR. WONG: And then the EPC costs, engineering, procurement, construction.

DR. SHEEHY: So the installation costs, they vary though depending on the technology. Which producer is going to get that money.

MR. WONG: Right.

DR. SHEEHY: But the engineering costs don't. So in general they lump, me installing a PV panel, if I own a PV installation company and you own a company that installs microturbines, we are going to -- in terms of producer prices you and I are going to be lumped into the same category, from what I understand, in the model. Because it is the same engineering expertise in terms of the model and who is benefiting in terms of jobs, from what I understand.

They can't -- I mean, the model doesn't have the resolution to differentiate between me as an engineer who installs PV and you, an engineer who installs microturbines or gas turbines. That's a level of resolution --

MR. LAWRENCE: It would be the specialty construction category in the NAICS code.

DR. SHEEHY: Right.

MR. LAWRENCE: And it does not differentiate beyond that. So the exact technology that is being installed by the construction activities or the construction portion of the input-output model would be the construction activity. It would not be related to the specific technology but related to construction in general.

MR. WONG: Right. My comments to what you just said is that the engineering expertise, if you do a cookie cutter approach to a technology, be it a solar panel or microturbines or an engine, that that's one thing where you can have representative numbers that can be kind of plugged in there. CHP, because of the thermal load and site-specific requirements, tend to require different levels of engineering, which can drive costs quite high.

MR. LAWRENCE: Right. But the costs provided are detailed by the individual installations. So for each installation, for each of the technologies, any installation of that technology, we have a different cost sheet. So what did it cost for that generator to put that particular technology in place. That's the cost. So the cost of the technology would include the engineering design costs for that particular technology. Because the installer is buying it in the marketplace at that market price. So it is a product that he is buying.

DR. SHEEHY: We know if you installed CHP or not based on the project cost breakdown worksheet.

MR. WONG: Right.

DR. SHEEHY: We know. So that cost, although -- So the thing is, and I don't know if this is answering your question. But the model does not differentiate between the higher -- it is just an increased cost in terms of the model. It doesn't change the construction category. Because you are a specialized engineer and you can do CHP, you are still in the same category if I didn't install CHP. It's just that you are putting more money into that category.

MR. LAWRENCE: That's correct.

DR. SHEEHY: You are not adding a new category based on expertise. You are adding dollars, not categories.

MR. WONG: Right, okay. So you would have a change in dollars for say, a CHP project that does thermal versus steam versus a chiller.

DR. SHEEHY: Yes, exactly, yes.

MR. WONG: Okay.

DR. SHEEHY: So we would know. We know what percent of installations have CHP. We know in even further detail which ones have chillers versus boilers. So we know that detail. So we know what sector a chiller goes to and what sector a boiler goes to. And then in terms of engineering though, those are all going to be -- Regardless of what you are installing there's going to be one to two engineering categories, engineering and construction categories.

MR. WONG: Okay, all right. And then I'd point you to the second hard-to-read graph there. This is the one that starts off as environmental and go down to job creation. Again, this is one of the focuses of the report. You have job creation, installation and maintenance. You have a negative under utility. What is the assumption there?

MR. LAWRENCE: Well the assumption there is that the installation of distributed generation results in less installation of capacity by the utility.

MR. WONG: I understand, that's what I assumed you were going to say. I would point you out, and you may have already looked at this study that was done, published in 2007, and it was by EPRI and E3 did this study called the State Technologies Advancement Collaborative. Does that sound familiar?

MR. LAWRENCE: I've heard that title.

MR. WONG: And the lead analyst was Snuller Price from E3. And if you haven't looked at that I would suggest that you do. Thank you.

MR. LAWRENCE: Thank you.

Okay, without further adieu I am going to turn it over to Mohamed.

DR. EL-GASSEIR: It's good to see a lot of familiar, friendly faces here. My name is Mohamed El-Gasseir, for those who haven't met me before. I'm with RUMLA, Inc.

We have a real challenge out here to produce results in two weeks but that's the difficult news. The good news is we have done quite a bit of work before in the past. You know, from Milan, Italy to Hawaii on self-generation and mostly distributed generation. So I guess that can, along with the fact that I have been quite much involved in the design of the California market. So I wore two hats. I wore the small stuff that is below one megawatt and the big things there, including the California grid and the WECC.

And so what you are going to hear today is a methodology that actually bridges the gap between the two and provides that connection. Which I haven't seen so far. It may have been done in Europe. I haven't followed up recently but I doubt it. And I want to give you the message that now, before we get into the details, what's guiding our work and what you are going to see.

(Advisor Ten Hope exited the meeting room.)

First of all, it's like the real estate, it's location, location, location. You want that stop, go for the location.

Now the CEC has done a very nice job at moving in that direction by sponsoring that work with the Energy Efficiency Program. Today we will try to turn the notch up higher and go even more in detail and link the small markets, the evolving market, with the big market.

The second thing is you are going to hear the message that this stuff, these programs have to be integrated more with the utility distribution engineers, distribution planning and possibly even customer service. There is really no doubt about it. The time has passed when we were small, one application here and one application there, it doesn't matter. Now you have high fuel prices and you have greenhouse gas emissions reduction driving it. You are on the verge of emptying the middle there where there will be a fast growth and it has to be managed and managed right.

The third thing. Whatever method you do, it must be seamless. Not only across all these small technologies but across the programs. It has to be the same, I'd say currency, between distributed generation, self-generation, energy efficiency, payments to QFs and how the big ones operate down to where the ISO stops seeing things, which is about one megawatt.

So I hope this work will provide you the number that you want to see. There will be benefits. I will cite and I will talk about them. We can't evaluate them because there is not enough time. There is not enough information to do that. But they could be very significant.

We were asked to develop methodology to

examine what is on the ground, what is available today, and if it is not sufficient to propose something different. And we are proposing -- and hopefully it will be also a road map for other efforts to follow it.

Now, I've got many slides here and I don't, I want to skip Task 1, the review, and go to the Task 2, progress. And in the process of talking about it I will provide samples of what numbers and why some things are more important than other things and why we are doing what we are doing.

The approach we are going to propose is five steps. Identify these benefits and costs. I am not going to talk about the costs, that's Philip's area there and his comrades. They deal with the costs. I deal with really the grid. Anything that relates to the function of the grid, the requirements of the grid, directly or indirectly, you are going to see it in the matrices that I will go over.

And then I will define what are the evaluation requirements. How do you evaluate a program. Based on my experience in this business both at the micro and at the macro levels of the industry.

Then I am going to say what we need here because these are installations that are already in place. We need a retrospective assessment. But because we are going to assume 30 year life we need a prospective assessment and the two have to be integrated together.

Now this is what I call the benefits and costs matrix. I just put it together. Please look at the headlines of the columns. Don't look at the details because we are going to get into each column separately.

Our charge is to look at the benefits for California as a whole. To do that you have to add the participant and the non-participant. There is another category that you don't see here. I just don't have enough room to put it into this slide. Which is those other guys who are neither non-participant nor participant. Other taxpayers, other members of the -- you know, other utilities' customers.

But it is sufficient here to identify what belongs to the participant in terms of benefits and costs, what belongs to the non-participant. And if you add them up the interesting things are that the net that emerges is what we have to be concerned with and a couple of things that dropped out. And thank God they drop out because they are nasty, okay.

One of them is electric bill savings, okay. And the other one is the lost revenues. They cancel out. Lost revenues is a cost to non-participants when somebody drops out. And electric bill belongs to the participant so that cancels out. The same thing with the standby charge and all the items, whether it's official or not it drops out.

Another one which I have to correct here under participant. It is not tax credits, it is the incentive payments. They get that as a positive income. And I am told it doesn't belong to California or somebody else. It actually comes from the non-participant ratepayers so that also cancels out.

And just to save time let's skip the next two slides and go directly to the California benefits and cost matrix because that captures just about most things. And these are the things that we need to talk about and talk about them very seriously because that is what is going to drive the numbers that we are going to present to you shortly. And some of these have been captured by previous studies. Most of them have, some of them have not.

There is the customer reliability benefit. The customer has self-generation, has a reliability benefit. A lot of it. And that can be very significant. In fact, for those that it is significant it is sometimes big enough that they go ahead and do it, they don't care about your incentives, okay.

Then there's the local reliability benefit and that is the most difficult of all to evaluate. Because when you have self-generation you have a reduction in the load on the local distribution circuits. That reduction of the load for the local distribution circuits would allow journeyman distribution engineers during an outage to manage the system easier. They can switch loads, they can do better sectionalization.

Believe me, I have talked to distribution engineers in about 27 utility systems all over this country. It's an art. Part of it engineering and part of it experience and expertise. This is why I said in the end, one conclusion, if you want to design good programs, somehow you have to integrate the distribution planning operation functions for the utility. That can be significant as well.

The customer environmental credits. If the customer captures credits for themselves by selling them, selling these credits. Well, you know, that's a benefit.

Otherwise it is a societal.

Then there is the fuel-for-heat savings. This is for the CHP projects.

The avoided energy cost is important. I will come to it again. That is the one to focus on. In most normal situations it commands 80 to 90 percent of your value, of your benefits. Unless you go for the low-hanging fruits or high value applications then these come into it.

And out of the avoided energy costs comes a whole bunch of other things including congestion losses instead.

Avoided ancillary services charges. Easy to evaluate. It's small, probably two to five percent of the value.

Avoided CAISO charges, grid charges. It is also very small. But if you are counting the beans it's important to put it there. It is easy to evaluate.

Congestion reduction savings. That's a big one. And that one is actually -- we want to go into it in detail. We want to explain why we are doing the modeling we are doing. Then there is distribution capital deferral savings. You notice it is not T&D. I just haven't seen a convincing argument there is a transmission deferral benefit for small generation unless under very unusual circumstances I will go into later on.

Then there is distribution loss savings. And that's different from transmission losses. That's significant. Ironically it could be even more significant than distribution loss savings. Which people have looked at before.

Gas price moderation savings. Elasticity and price of demand are another name for it.

And that basically summarizes the list of benefits. So I am focusing the rest of the talk about these. Now my next slide gives you sort of a qualitative. Basically what I have seen from all these studies. A qualitative assessment of what to expect in terms of relative value.

Customer reliability benefit. Its value can be quite high, okay. The likelihood, needs targeting. When you say, well how probable I am going to capture this benefit. I'll tell you what, it depends if you target your applications. If you talk to, you sell to particular customers in the Silicon Valley there is a high probability that if you have a high special issue item, people will do that, okay. And valuation. It's doable, you can do it. Actually it is not very difficult at all. It basically requires value service information.

Local reliability benefits. It can be low, up to a medium value. Now that also needs targeting. The valuation, very difficult. And I add very, not just difficult, okay. That is, we didn't do, we can do. These first two, we are not doing it, okay.

In particular, we can identify areas based on the information that we just received from two utilities and the other one that we will be receiving shortly, by Friday I hope. We can say, well, you know, that particular zip code, look at it, okay. It goes then to the utility for further study, further assessment to say, is that really true? They can talk to their distribution engineers to see if it is true or not.

Customer environmental credits, societal environmental credits. They can be high, it's doable. You know, my judgment it is difficult for the societal benefits. Things really where you use damage functions or some other means. How far you go down the chain with the valuation.

Fuel-for-heat savings. Again it is high if it is targeted and it is easy to do. And I understand TIAX will be doing that.

Avoided energy costs. It is the highest. It is certain. You will definitely get savings there and it is doable.

Avoided ancillary services. It's low, it is certain and it is easy.

Avoided CAISO charges. Very low. It is also certain that it will be there and it is easy.

Congestion reduction savings. They can be high, they can be very, very high. I found that none of these installations, unfortunately, were on-line in 2001. And I can bet you, some of them were on-line in 2001, January in 2001. They would have paid off probably in a few days at the prices, okay. So that one we need to look at because it is important.

Now the thing is that avoidance of congestion is not for the self-generator. I think it is the avoidance of congestion for the entire service area. That is why it is very high. And I'll explain the difference between the two.

Distribution capital deferral savings. It can be high, it can be low, it depends. It needs definitely targeting and it is difficult. It is not very difficult but it is difficult. If you know what you are doing, where you are going you can -- We have a mechanism we are going to use, and I'll come back to it later on, with the data that we have. How to identify those cases.

Distribution loss savings. Low. It is certain, it is doable.

Gas moderation. I think given that we are talking here about what, how many megawatts?

DR. SHEEHY: Two hundred forty.

DR. EL-GASSEIR: Two hundred and forty. Quite frankly it is very low, that will not make a dent. But it is, you know, it certainly makes a little difference and you can calculate it. And this is one of those things that should be done to illustrate that as you go into a high saturation and more applications because the fuel prices are going to change, the picture then is something to watch out for.

Now what are the evaluation requirements. Number one to me, I must capture market realities over the entire service life.

Okay. Two, whatever I do must be seamless across all markets and technology types. I said that before.

And third, conduct both retrospective and prospective assessments.

And fourth, we must maintain transparency without compromising one or two.

And then it must be easily integratable with public data resource planning tools. In particular the IEPR and anything else that is publicly available. Whatever we do it should be easily integrated with those things.

And the sixth one. It is easy to use, available to all parties in California. That requires some kind of an agreement on the modeling tool, one of them. We are using, we will be using General Electric's MAPS. And I am not endorsing it in particular. It is the one that we know how to use. It is one of the best and most accurate and the oldest one. But there are other models and there has to be some kind of an agreement. I remember the Legislature had to actually say Elfin was the model to use at one time for the QFs. So I hope it doesn't require a legislative act.

Now the market realities. The energy commodity dominates. I have no doubt about it. The exceptions are heat and power applications and on-site reliability applications. In some simple cases that could make a big difference.

Then there is the T&D benefits. I think they are small except where locationally targeted. And particularly the distribution. As I said, just kind of glance over the T and focus on the D in this case.

Zonal energy commodity markets in transition since 2001. We are in a zonal market still, probably through December of this year. It is quite interesting that next year is targeted as the new market. Which we are going to focus on as well.

So additional market realities. It is a mix of regulated and unregulated segments. You have got utility resources, you have quite a bit of merchant generation there, you have got the CAISO running the markets.

And the mix has been changing over time, okay. So from zonal to nodal pricing regimes. That's coming probably December or January. Then we have a spot market that went to long-term contracts. A totally spot market in 2000 and 2001, early 2001. That's what created the meltdown. To long-term contracts to cover the short position of the utilities. To the resource adequacy. Now we need to integrate all of these together.

Now the seamless application. We have distributed generation, energy efficiency, payments to QFs. The PUC just made a decision, I believe in May, which actually comes close to what I am proposing except it is more out into the future. The bulk power markets. All of these, they have to speak the same language when it comes to that common commodity, which is the energy commodity. It has to be based on the same thing. No one should say, I'll use a proxy here and the other one use a production cost model. You can't do that.

The economic efficiency and equity

require same valuation techniques.

Non-energy benefits can vary as add-ons, okay.

And you need the integration.

Now, the investment, as I said, is 2002 to 2007. I guess 2006, right? All right.

So the service life of 10, 20 years, you know. I made a difficult assumption of 10 to 20 years to complicate my life. I like to always look at the complicated things. But you are going to make it easier, 30 years flat for all of them.

Program evaluation must cover past the future. So the prospective assessment. The retrospective is from 2002 to 2008, okay. Even thought there are still a few months in 2008.

The prospective is 2009 to 2026 if you assume 20 year life. Now that also happens to be convenient for us because the new market starts in January 2009. So we go right and sample that.

Now let's talk about the retrospective. The established market realities and the identified benefits and measurable benefits. The market reality is that the energy commodity really is dominant in this case. And that means expect that 90 percent of the value will probably be energy commodity. I will be surprised if it is not.

One of the reasons I would be surprised if it is not, I am talking about the whole thing now, I am not talking about a particular CHP application. Because I don't see any evidence that these investments were targeted at distribution deferral, which could change reality. Or was targeted at serving local reliability. Or was targeted at serving customer reliability. So until you capture you benefits it probably would be most of what you are looking at is 90 percent-plus there. So we have to pay close attention to what makes up the cost of the energy commodity.

And that's also the remarks for zonal. Now in 2001, to I believe the end of 2003, DWR actually did the procurement for the short position for the IOUs. I am hoping to get that data from them. If I don't I can get it from the IOUs. That's kind of old history. I am hoping that it is not something that they will hesitate to give us because it is quite old information. Usually utilities and others are very protective about that.

In 2001 -- 2004 until now, through now,

through 2008, the IOUs self-procure and schedule. And we will be looking for the cost of generation on the margin, okay. What is the one that is actually procured to serve on a daily basis. So that's basically, in other words it is historic information the basis for that.

And I think you will see that there will be higher costs in 2002 and then it starts to decline as the market continued to stabilize. And then as energy prices got higher, in 2007 you will see an increase again.

We identified benefits. That's the benefits that people talk about. It's not the one necessarily measurable. We have CAISO-delivered energy savings. I call them CAISO-delivered because CAISO actually provides this energy. Congestion cost reduction, ancillary service cost reduction, reduced delivery losses and gas price moderation.

T&D upgrade transmission. I put it in-between parentheses, claimed, transmission deferral. And then there is distribution deferral.

The measurable ones are the ones that have check marks on them. That we can deal with on the basis of information we have. Procured energy savings, congestion cost reduction, ancillary service cost reduction. Those are easy to do.

With respect to T&D it is the distribution deferral, including subtransmission, which means probably up to 69 kV circuits.

The methodology is symbolized in this diagram. We start with the location, megawatts, production profile from the metered data.

We identify the feeder and distribution substation. This is the -- We took a long time to get the production profile location. And it took a long time to get the feeder and distribution substation identified. I believe by this Friday we will have most of the information in hand as far as the feeder and distribution substation identification.

From there we'll try to figure out whether there are subtransmission deferral benefits or whether there's distribution deferral benefits. And I'll explain how we are going to do that. But let's just follow this diagram.

Next we will identify the transmission substation that is linked to the feeder and distribution substation. Now because it is -- that is ideally what I'd like to do. But because there is no time we are going to take a shortcut here.

And the shortcut we are going to do, we are going to use zip codes. And the reason I want, I want the transmission or receiving area substation, transmission station identified, because these are the ones that lead me to the ISO price. What the ISO is, you know, commanding for prices closest to that area.

Now for the retrospective that is not much of an issue. There are only three pricing zones in the ISO, okay. NP-15, SP-15, South Path-15, North Path-15, and then the newer one that was created I think in 2002 or 2003, ZB-26. Which probably we don't have anything there anyway. There is another area they were thinking about creating between Mexico and San Diego. That is of interest because there's a lot of congestion there. But anyway, that's the reason we want to identify the locations. From there we can get the CAISO pricing zones for 2007, 2002 to 2007.

Also 2008. We will treat it special, CAISO pricing zones for 2008. And from this, the result is going to be the energy commodity values and related benefits. Energy for both -- for all of these years.

Now the energy-related savings. There is the energy procurement, which will be comparing what the IOUs paid to get that energy versus what the self-generation costs. Basically it's self-generation fuel costs. All right.

And congestion that would be avoided by the self-generation in the congested zone. There are two cases here. If the self-generation is small and it is not going to change the congestion, taking it out, well, then at least they have avoided the costs that would be charged to them by -- passed on from the CAISO to PG&E or Edison or San Diego to the customer. That's an avoided congestion.

But in some cases if there is enough to take off. If I said, okay, this self-generation was not there there would be congestion. Then you are talking about a whole different story. You are talking about a very large benefit. And even if we don't find that in this case. I don't know if I will or I will not. There may be times in the future where this would happen.

Now the MAPS modeling we are going to do is going to simulate every hour of operation. And if there is congestion it will say, that line is congested. And what happens is prices will go high in some places and lower in other places like a seesaw game, okay. So if you have the generation in the high area -- probably you have most of them in the high areas because they are where the load is, it's in urban areas. They commonly are congested because the power tends to flow to the urban areas. Then you could have some very substantial congestion.

Think of it this way. Suppose there is a 1,000 megawatt line. A critical line that brings power to Southern California. That line gets congested around -- they do the dispatch, they find it had to be loaded to 1,005. In other words there are six megawatts too much, all right. If I took that self-generation, I put the self-generation back, there's no congestion. It may be 850, 875. The benefit in this case is huge. It will be Southern California load multiplied by the delta in the price. You are talking here about quite a bit of money, okay.

I have really actually seen situations

like that. I can't say that it would be there or not. I don't know if it would be there or not. But we will give you the methodology that at least says watch out for that. Because in the future as you do more of these installations they will start attracting that kind of benefit. As I said, if some of them were operating in 2001, early in 2001, they would have paid for themselves in terms of benefit.

So the ancillary services. The self-generation avoids CAISO costs, basically. And there are other smaller charges I don't want to talk about right now.

The retrospective -- the retrospective assessment methodology. The broad picture is that we have got a period from 2002 to 2008 and we have two sides of it. One side where DWR did the scheduling of the short position. And I just talked to a former manager at DWR and he said, yes, the detail is there. We can tell you in detail how much it cost and some of the exorbitant prices they had to pay in those days. And then slowly as the market stabilized and the PUC removed the scheduling authority obligation from DWR and gave it directly to the IOUs, the IOUs started approving stuff on their own.

Now I can use MAPS. And if nobody wants to give me that information I can use MAPS and I can -- I know which ones are DWR contracts, non-dispatchable contracts, and I can find out what the equipment costs. Why it didn't dispatch. But I prefer to use -- Since this is in the past I am going to use all I can use in terms of my leverage with the people I know. Give us those data for God's sake, it's really useful. I don't need to know who the sources are, I just need to know the prices, insert the prices in our model. That will make an ironclad assessment of the value in the past, the retrospective assessment of 80 to 90 percent plus of the benefits.

Now let's talk about distribution deferral savings. This will apply to transmission if it can be done. I am extremely skeptical about that, okay. I know some people won't like it. But here's the reason, okay.

We start with the self-generation location. We identify the feeder and transformer. Then we get the feeder and transformer ratings and peak loads. This is the stuff that we got from two IOUs. And the third one is going to come because they had much more information and it was archived and all of that. It's coming, hopefully by the end of this week.

So now we have the transformer ratings, the transformer bank ratings, and the peak loads. At least three points if not five points peak loads and the feeder ratings as well.

Then we determine if the self-generation could have deferred the upgrades or not. Now this self-generation, understand they were not put there to establish any deferral. They were there, they had them as a gunshot approach, right. There were incentives and people just put them in.

So what I am going to do is I am going to basically pretend I am turning them off, okay. And find if there is any loading on the feeder or the bank that exceeds the permissible thermal capacity of these feeders, okay. Now that's the end of that. That just says maybe, okay. Then we have to look at it closer. So the load from the behavior of the peak, the load of the peak on the feeders. I can find out whether this is really a good candidate or not.

And a good candidate is, that's the most -- that's the key thing for the whole thing. You are looking for highly saturated circuits. Circuits operating at or near their limits, okay. But there is no load growth. There is really a trickle of load growth.

Those are the killers that, why the utilities didn't invest in any upgrades. Because it is too hard to justify the investment when you know it is just, you know, there may be another 100 kilowatts of growth that will put you above the top. But it is not important to violate the thermal criteria for a couple of hours in the summer. If this is an old neighborhood that is not going to change, that's where the home run is.

Because if there was a self-generator there and I took him out and he is a half a megawatt, the self-generator is half a megawatt, suddenly I have an overload. A would-be overload of substantial -- I know it will trigger an investment by the utility. They have to do something about it. And that would be the home run. How many of these cases? I suspect there will be some because we have 1,000 sites, right? I suspect there will be some, okay.

And incidently, we are going to aggregate them in zip code because normally a feeder is accepting special situations and we can consult with our friends at distribution planning and say, is this zip code covered by the feeder or not. Because we don't need to look at every particular installation. Especially if they are rooftop PVs. So you can see from doing this procedure you can actually see the groupings for how to do it in terms of incentive investment, if you really want to do it right. So we will be looking for that.

But some distribution engineers are very artful and creative and stubborn. You know, I could route my load this way or that way. I can actually do a sectionalization shift in load here and there and you end up with nothing, okay. So some, maybe we will present these results as basically bookends when we say that it could be as much as that. And then it would be up to further investigation to confirm or not. But suddenly if it is a very small load growth area it is saturated. Banks are saturated. Both banks, these are both -- two or four banks in the transformer in the substation. It is a very hard case to argue.

The prospective. We are still dealing

with the same investments, 2002-2007.

The market realities. The energy commodity is expected to dominate. But remember, I didn't put a number on that intentionally because things could change in the future as you progress.

Then we have nodal bus-specific pricing takes over. The ISO has, is going to have over 3,000 buses and the system will price -- each one of them tagged with a price. They change every five minutes. But the ones we are interested in are the hourly prices for the day because that's where most of the market settles. It settles 90 percent-plus. Maybe 95 percent of the market settles at the day-end prices.

So the energy-related savings are the following. And listen to this carefully because there may seem to be double counting and this dichotomy is very important.

There is the CAISO-delivered energy savings. CAISO-delivered to a bus, okay. A station, okay. So you have a generator and you will say, what is its worth, its generation. It will be that bus that is closest to that generator. That's why we asked for the location and the circuits and all of these things. That is really the most important thing you can do now. What I said is a much higher accuracy in terms of establishing and more suited to the structure of the market.

There's the congestion cost reduction. And I said that has two components to it. The congestion that is subject to like everybody else, okay. It's part of your bill. There's always some kind of congestion charge there. But under some circumstances, hopefully we are going to reveal them by the MAPS modeling, it may make a difference that self-generation actually avoided congestion. And when it does it is going to avoid it for the entire service area or most of the service area, normally above the south or north of a well-known, identified interface. Or east or west of it. A congested interface. That's important to find out.

Ancillary service cost reduction. As I said, that's just ISO passes the -- it's about five percent of the energy charge, to support basically spinning reserves. We could take ISO values for that.

Other avoided charges. The grid charge,

the grid management charge.

The reduced delivery losses and gas price moderation. Now I deliberately said reduced delivery losses. I didn't code them distribution or transmission because there's an incredible difference between them. You're going to look over there and look at that.

The distribution deferral is as we talked about before. Now what are the measurable benefits. They are more or less the same thing. CAISO for the prospective. CAISO-delivered energy savings. And incidently, in this 27 and 28 there is a typo there. I think it is prospective. The little title at the top it said prospective, not retrospective.

MEMBER OF THE AUDIENCE: In the printout?

DR. EL-GASSEIR: Yes, in the printout in 27 and 28. I copied it because I can't stand typing. But there is important differences between the content, okay. So again, 27 and 28 at the very, very top it's Prospective Assessment, not Retrospective.

The prospective assessment follows generally the same steps except at the end. You start with the location, you get the feeder identified. Subtransmission deferral, distribution deferral. Subtransmission, by the way, is something above 12 kV and between 60 or 69 kV. San Diego is 60, I think. Above 60 kV belongs to the ISO. PG&E above 69 belongs to the ISO. Edison starts at 230 kV.

So there's differences on what is distribution and subtransmission and all that. I don't want to touch the ISO basically. And in fact I know of only one subtransmission application. Two, two that were really good. One in Hawaii, in Maui. And that was worth a lot of savings. And the other one, a little area that is served by Edison in DeAnza above Palm Springs, were huge savings. But that's rare. And again, you have to look for these high values. Mostly it's in the distribution.

So although we proceed, again, identify the transmission station. And from there we get the CAISO pricing bus for 2009 to 2026. We get also the CAISO pricing zone, okay. Believe it or not, even though the ISO is going to publish prices for each bus they still have to deal with pricing zones. Because the ISO sells energy to the IOUs at the load zone, it doesn't sell it to them at the bus by bus.

So we are going to give you the results first at the pricing zones, okay. We may need more time and we may actually be beyond the September graph to the next one to get to the results in terms of comparing the ISO pricing bus. The distributed generator or the self-generator, versus the one that is measured against what the load take-out, which is the zone.

Now this is just kind of summarizing saying what we are going to do. We are going to simulate it using Security-Constrained Economic Dispatch, a SCED model. There's about five or seven of them in the marketplace. I think the CEC uses PowerWorld or something like that or ProSim.

We use MAPS. MAPS is an engineer's model. It's an engineering model built for engineers. It's difficult but it is the most detailed. And it was built from the bottom up for dealing with these things. Basically it dispatches the same economic dispatch except it observes transmission limits on the lines that you specify.

So the ISO. A very quick review if you

want about the ISO locational marginal pricing. It's bus-specific. They publish day-ahead, hour-ahead and real-time. We're interested in day-ahead.

They use the nodal prices to settle the whole market transactions.

And the utilities buy at the zonal prices. Which is basically if you figure out by taking the nodal prices weighted by the megawatts, divide them by the total megawatts, you get the zonal price.

The IOUs' congestion risks can be mitigated by CRRs, by the congestion revenue rights. Which means they hope to get their money back after paying that congestion charge. That may or may not happen efficiently.

Now the locational marginal pricing. Go to the bottom of this thing. It consists of three things. System energy, that's the same. That's like, what is running on the margin. That's the same charge. Everybody gets that everywhere, whether it's the IOUs and a couple of other places. Members of the ISO.

Then there is a transmission congestion charge. Which may or may not happen, depending on the season, depending if it's a line out or what's going on. And remember, transmission congestion is like a moving bottle. They fix Path-15, we've got more congestion on Path-26. They are trying to fix Path-26, the congestion will come somewhere else as you build more plants and you shift your bottlenecks.

Marginal transmission losses is the one I want to now shift your attention to it. That's the one that nobody is talking about although it can be very significant.

Now what the ISO does is it uses up what is called a full network model. It's actually a truncated full network model. To do their, to figure out the prices for about 3,000 buses. And they use them to pay, to settle generator supplies at each, at each bus sometimes and pricing zones. And the items will pay on the takeout buses within the comprised zonal load zone.

The impacts on LMPs' marginal losses can be significant. Let me give an example. And this is a real case, it is not a simulation. New York ISO, the first to adopt marginal losses in the estimation of its prices. There was a specific hour, I forgot what it was, where the price was, in Long Island and Manhattan, was about, was about $90 per megawatt hour. And across, upstate it was about $50 dollars. The difference of $40, almost 40 percent difference.

It was not caused by congestion, it was caused simply by marginal losses. Because what the ISO model does to compensate for marginal losses, it depresses faraway generators. It depresses their prices. It punishes them and increases the prices for the generators that are close to the load.

That's why this stuff is very important for the program. It is a hint-hint that says, you have got to look at where the load is. And you have got to look at the price signals that the ISO is sending as far as marginal losses. That will provide a hell of a lot of incentive if you can figure a way so they can get paid. The marginal losses are twice-average losses, remember that.

And I predict actually -- We ran a simulation and I'll show it to you a little bit later, that it could be significant here in California. Especially in California. Maybe more than even New York.

There is this, also the matter of

spatial LMP differentials. They are giving it special differences because of the congestion, because of marginal losses. And PJM, there were differences of $10, $20 or $30 in quite a few hours. PJM was the oldest, the oldest ISO.

Now the other thing that causes, that causes spatial dispersion of prices. This is something I did on a spreadsheet, actually. I put a model of a three-node flow, on three nodes. Three buses, three nodes. Bus A and B have bid prices. Node A and B have bid prices. And Node C is the result in the price. Now you would think that if there is no congestion the price at Node C would be the average of the price at, you know, A and B. That's fine if there is no congestion. But if there is congestion the flow gets distributed in accordance with the ratio combination of the impedances on the line. A measure of the resistance of the flow, how the flow divides.

And look here. The price at C could be 500, 750 times the price at A. Okay. Now you get into the yellow and orange and red, okay. Not only that, you could actually -- It's a settle that actually goes down. You can also get negative prices. And in fact in simulations we found out there were negative prices. And guess where they are? They were where there was no load, very little load. There is load but very little.

And that, unfortunately, is in the Mojave Desert where there's a lot of sunshine. So unless you are going to put casinos there don't put self-generation. You would be in a sinkhole. You will actually have to pay to generate, okay. You have to pay the ISO to take your generation. That is represented by these negatives things, the legs it is sitting on.

On the other hand, right across a congestion, the other side of the congestion, you can get a price that goes through the roof. And I happen to know that all the ISOs shape these things. First of all, they don't like to see the negative, they pretend it is not there. I don't know what they do, they have different rules.

The ISO is careful and it hasn't declared -- maybe that's the reason they have been late two years now. They haven't declared what they are doing about that. I know it is there because we simulated it and we told them about it before it and resulted actually in a delay of two years before the last delay.

But the tough one is the one that you normally shape. They put a cap on it and generators don't like that. They say, why are you, why are you capping it. But, you know, that's what happens when you are messing around with economics and AC power flow. It's a wild game, okay.

But that's where you want to target your self-generation. And when we do the modeling we will find out. I don't, I don't expect to see these extremes. This is just a three bus model. But there has been quite a bit of transmission work over the years by the ISO, by the key IOUs, so some of the congestion has gone away.

How are we going to emulate the LMP methodology? We are going to use the -- there is a typo there. We are going to use the CAISO, we are going to use GE's MAPS model. We assume full competition. And we exclude sporadic market forces. Which says that I am not going to be dramatic about it. There's, you know, a lack of competition or very high gas prices so we get into that. We are not going to do that. We are going to assume a very nicely behaved marketplace.

I think I told you the MAPS model does actually simulate the entire (indiscernible) and as a pool. The three IOUs we combine as a pool. We separate LA, we separate SMUD, we separate the others guys, okay.

Computes transmission flows, congestion. And in response to your question, Eric, earlier, it does also compute emissions. And that is just a byproduct. We can easily, you know, produce results not based on a proxy like a combined cycle, but based on what the system dispatch is, constrained or unconstrained, you know. That is a byproduct.

I don't think it will cover all of this menu, you know. I don't know if it covers particulates or not. It said it covers CO2 and NOx. And it would cover SOx but SOx we don't have an equivalent.

This is generally the MAPS construct here.

So we are going to focus on the California market.

Assume bidding at marginal costs. Which is a big assumption. That means everybody is honest, everybody is bidding their marginal price. That means that commodity savings are probably going to be low, okay. I am going to make that -- And then with a caveat that by putting in an additional analysis that says, what could be the adder that will bring me to the -- Because people when they bid they don't bid their marginal costs, we all know that. They bid to the extent they can to recover their variable cost plus some to pay for their fixed investment and anything else they can extract from the marketplace.

So that data is based on the CEC, WECC, REI, EIA, FERC forms, GE and all kinds of things. And one thing that is going to be really interesting in this case, we are going to use the metered data that we have and integrate it into the MAPS model. And this will be the first time any model of this type has actually gotten down to that detail.

And I know you're saying, well come on, you do a lot of things for about 230 megawatts or whatever. Okay. But remember, we are also making methodology and there are non-linearities. You know, don't discount prices, okay. There are surprises.

The full competition. I think you can review that by yourself.

We don't want to assume low hydro although we are in a low hydro year. We are in a drought, actually. Oil or gas price spikes. There is no time really to do these additional runs. Or prolonged generation or transmission outages.

But the important thing we want to emphasize is the price differentials. Now this is from a past assessment I did which is using MAPS. It shows a difference between San Francisco nodes and the average from all Northern California in dollars per megawatt hour. And you can see -- and this without marginal losses. You can see that there's almost no difference. Why? Because there's no congestion and there's no assumption of marginal losses to kind of really skew prices, to deform prices. So you will find that in 2007 it's about eight cents per megawatt hour. In 2008 it's a little less, six cents.

But look here what happens. This is the duration curve of the price dispersion. Up here when we have marginal prices in, which the ISO is going to do. You'll find that the average, okay, that San Francisco is higher in 2007 by about $4. Now remember, that's per competition, okay, and everybody is bidding their marginal, marginal costs. I tell you, in the real world you are much higher than that because those generators in the coastal area, particularly in San Francisco and near the load, you know they were. So it's $4 higher. And it continues until 2010 and gets to about $5.

During maximum differences I think they are about $10 a megawatt hour.

And this is the duration curve of that.

And I guess that concludes my presentation. Any questions? I'm waiting for Eric at least.

MR. WONG: Maybe somebody else. I only have one.

DR. EL-GASSEIR: You will make it easier for somebody else to ask, okay.

MR. WONG: I'm waiting for Jeff to come back up, or come back at all.

Eric Wong. I just have one question. Mohamed, I know your work from the past and you are usually very, very comprehensive or are very comprehensive. So I am thinking my question, or what I am looking for is embedded. And I am looking at the California benefits and costs matrix.

DR. EL-GASSEIR: Yes.

MR. WONG: You have all the listed benefits. I am looking for avoided capacity costs. Is that embedded in something?

DR. EL-GASSEIR: Yes. That relates to a question I got from an e-mail from somebody who said --

MR. WONG: Not me.

DR. EL-GASSEIR: No, not you. It said, aren't you -- You're going to take this self-generation out when you run your model. Don't you know we are going to have to replace it with something. I said, yes. And we would look at it. We looked at it. Something called a lost load probability. If that declines you put in a combustion turbine. Okay. That's the varied capacity. And if not, both in terms of capacity energy, if there's a surplus, which I don't know if there is or not, the model would pick that up and there will be an increase in the cost of the energy but there may not be any capacity value.

Now capacity itself can be calculated

separately outside of all of this modeling under another whole separate criteria and there is a reasonable rationale for that. It is called the resource adequacy. And I think they have, in fact, established a very elaborate procedure of how to even intermittents to give them capacity value. Am I wrong? Is this -- I haven't followed that closely. But that's what we'll do. We'll go -- Actually we'll take it, the book, you know. If there is a capacity value it will be done separately by itself.

MR. WONG: So it is not going to be part of your analysis?

DR. EL-GASSEIR: No, it will be part of our analysis.

MR. WONG: It will be part of your analysis.

DR. EL-GASSEIR: But not -- I mean, that's the easy part. Believe me, okay. The only thing is, as I said, the only qualifications, when we run the model we look at loss of load probability. I mean, the total is about 200-plus megawatts.

Is the system's lost load probability going to really be affected? Normally not, okay.

But it is also a non-linear function. Aside, you know. If there is then you have to put in a combustion turbine of 200 megawatts or something like that and run it. Then you have a definitive capacity for the capacity benefit.

And then we do separate from the MAPS model and all of this stuff, we look at what the resource adequacy requirements are and how you are, you know, what's the evaluation capacity and how you do that. We make a different statement about the capacity value. But it could be modified by the model. The model could say, well, there is really no need for excess capacity, or there is.

MR. WONG: To me the question is for Phil. Where would this, what he just described, be discussed? Is it a separate section outside of his section in your report? I just want to make sure I can find it.

DR. SHEEHY: It will be in my section.

MR. WONG: It will be in your section.

DR. SHEEHY: Yes.

MR. WONG: Okay, all right, thank you.

DR. EL-GASSEIR: Next?

MS. KOROSEC: Are you ready for more

general comments now?

DR. EL-GASSEIR: Yes, yes, yes. Susan, right?

MS. KOROSEC: Yes.

DR. EL-GASSEIR: You don't change.

MS. KOROSEC: Thanks, Mohamed, neither do you.

MS. BULLER: Hi. I'm Susan Buller from Pacific Gas and Electric Company. And the first thing I want to do is thank the California Energy Commission and all of you guys for the opportunity to learn more about what is really a different way of looking at benefits and costs of distributed generation. And there are folks in this room who have been doing this for years and it is really delightful to see this kind of like, breath of fresh air that is coming into it. And we appreciate that and we appreciate the chance to comment on it.

I do have like three comments to sort of -- If you want to make this a positive, useful addition to the body that has already been done. Because you are aware of it. There's been a ton of work that has been done at the CPUC. The CEC has done stuff like this.

If you want to really usefully contribute to that then the guidelines that I have for you are transparency, perspective. And then the third one, I couldn't think of a fancy way of saying it in one word so I called it relativity. So let me expand a little bit on each one of those. And I'll be pretty short here, very high level, but our comments this Friday will have a little bit deeper look at it.

And we are looking forward to the draft report because that's, I think -- I think we are going to see a higher quality report at that point. And I am looking forward to taking a look at that. But basically transparency.

One of the things that's absolutely critical for this report or this body of work if it is going to be an addition to the examination of benefit cost analysis, rather than just another number that's out there, would be a road map between the choices that you guys are making in your methodology, in your inputs, in your assumptions.

The road map from what has gone before you, either in the Standard Practice Manual. I know you are familiar with that. With the PD that came out in the DG OIR a few years ago that talked about the benefit cost methodology for distributed generation. And that was done by the CPUC. If you could draw a road map between what exists today and what you have done, that is going to make it much, much easier to integrate your work.

The second thing has to do with perspective. And here I am going to take you back to the statute that you are following. And I think it was part of the quote that you put up on the board earlier which basically says that you are to look at the benefits and costs of ratepayer funded programs. With the fact that the Legislature pointed out that this was a ratepayer-funded program, leads me to at least a desire that the non-participating customers' perspective also be taken into account.

Now as a practical matter you have said today that that's not the perspective you are taking, you are taking the societal perspective. And this is due November 1. So here I am on September 3 saying, boy, do I wish you had a -- so granted, that may or may not happen. But again, this is something where the road map is really going to help.

Because to the extent that we are talking about what is included and what is not included in this study. You guys are talking about incentive, the incentive amount. If you were doing the participant perspective then it's a benefit. If you are doing the societal perspective it's indifferent. It's completely left out of the equation. If you are doing the non-participant customer, the ratepayer perspective, then it's a cost.

So the fact that you guys are quite clear and transparent about what the different benefits and costs are, then that's going to make it easy in the long run to maybe take what you have done and move it that step further to look at it from what, at least from PG&E's perspective is one of the more critical ways of working at this benefit and cost.

The third thing that I wanted to talk about was sensitivity. I think I called it relativity earlier. This has to do with the fact that some of the stuff that you're doing -- Mohamed talked about it a little bit. Some of the stuff you are doing is really, really easy, slam dunk. You know, you've got pretty good data.

Either there was a meter hanging there and Itron had it or the customer has provided you with information about what the cost of that installation is and it is part of the records that PG&E handed over, for example.

Other things, a little trickier. You know, if you want to put a quntification on something you may or may not be able to do that. So I guess what I am calling for is some understanding on your part about the fact that that might be true. And as you are reporting out on your results, some kind of softening of, you know. It's like, how many significant figures do we really have here when we know that this number was hard and fast and came from a meter but this number, we basically had to rely on an average between three studies, or whatever. But again, this gets to where transparency is going to be, is going to be very, very critical.

I think I am going to just close out by talking about that one more time. And that is that to the extent that you want to add to the body of knowledge that we have about a very tricky subject is that you do it, you do it very, you are very, very clear about how things happened. You guys are not going to be able to do everything. You are going to do the best you can in the time you have with the resources you could get a hold of. So if you want it to be something that can be built on and made stronger over time, then again I have to call for a road map and the clarity.

And one other thing. I noticed in the first presentation that one of the pages that had been in the handout that was also used in this presentation where you came up with the emissions factors. My comfort level just went way up because this has like the six footnotes of exactly where that stuff came from and that was kind of missing earlier. So it's like that's the direction that this stuff needs to go in. Where did you get the number and what assumptions did you make. Anyway, thanks very much for your time.

MR. ALVAREZ: Manuel Alvarez, Southern California Edison. A lot of information here. And so I guess I'll reserve the right to file any questions or comments on Friday as people digest some of this information.

But just so I understand. The issue came up about self-generation in and out. And as I understood the presentation, I am going to be able to see the analysis that will show the effects of the self-generation projects with the products and without. Is that correct?

DR. EL-GASSEIR: Yes. But I want to assure you that it is not like a QF-in and QF-out.

MR. ALVAREZ: Okay.

DR. EL-GASSEIR: You take it out and you say, okay, whatever, and what the cost is. It's a small amount. It's, you know, 200-plus megawatts. So we look at the amount. How to compensate for that for imports from the Northwest, all right. Or the Southwest or maybe somebody else.

It may turn on some more of the DWR generation. That's expensive. Some of the contracts there are dispatchable. But if we look at, you know, a couple of parameters. One of the lost load probabilities says, wait a second. For some reason the system can't run, okay. I doubt that would happen. They will add generation. And the tricky part is, when we add this generation where are you going to add it? Because if there is, for example, congestion. If you add it in the basin where the load is then their congestion case is gone, okay.

But you know and I know, siting a new

power plant or increasing generating capability within the South Coast Air Quality Management District is a very, very arduous process. So we look at, you know, we create scenarios. We look at where it comes, it comes from somewhere else. And it will show, you know, in that case there is congestion or what the impacts of it are.

MR. ALVAREZ: The other item you mentioned you are going to be examining, the distribution impacts.

DR. EL-GASSEIR: Yes.

MR. ALVAREZ: I guess I would just urge you when you are working on that section to make sure you identify the criteria that you used to figure out what those impacts are so that we analyze the criteria that you actually used --

DR. EL-GASSEIR: Yes, I describe --

MR. ALVAREZ: -- to compare the distribution investment with the self-generation investment.

DR. EL-GASSEIR: We do that. I mean, this is not a case-by-case assessment. It is not going to be that. It's a compromise, all right. We have, you know, almost -- We collapsed a lot of them into zip codes so you may have about 500 zip codes or something like that.

We have ways to look at it very quickly and pinpoint the ones that seem to be promising, from the information you gave us. And we come to the promising ones and then we'll provide some results. And results based on whether we think there is a strong case for a deferral or not. It doesn't mean those guys got the deferral. It doesn't mean the pattern is in the past. The generation is on and life goes on and all that.

I think one thing really useful will come out of this. That is a realization by those who design these programs, how important it is to target these investments if you want to capture distribution, okay. And, you know, in terms of value, frequency and all of that, if they look through them they will find them.

I looked for them a long time ago in Edison's territory and I found them. I worked with your distribution engineer and so with San Diego and maybe other systems. From ConEdison too to Hawaii. We found them. But you've got to look for them and there's a process to follow.

But remember, the time is very tight. We are exploring here whether there is benefit or not. Not finding it does not mean there isn't there, there are no benefits there. And we are going to make that very clear. If we find that there's none or very little it just means that shotgun approach somehow missed it. Because you know there will be, there will be cases like that.

I mean, you talk to your engineers and they will tell you, yes. One was on top of that mountain above Palm Springs where an Indian casino wanted to come on-line and it cost $20 million to put in a 34 kV circuit, $34 million. When I saw the case I said, I can put in gold-plated sunroof facilities and cost-effective, you know. So they are there.

MR. ALVAREZ: Okay, we'll look for that.

DR. EL-GASSEIR: Anything else? Any other questions? Yes.

MR. McCARTNEY: Hello, thank you very much for the presentation today. I am Wade McCartney. I am with the California Public Utilities Commission, Policy and Planning Division. The presentation was very interesting. I just wanted to comment and ask a few questions.

When you are running the numbers you are basically looking at this from the societal perspective only?

DR. EL-GASSEIR: That's what I have been told, from the societal perspective only. My comment was, given the fact that we have very limited time I said, that's good, actually. Because I cancel out two things. I won't need to look at time-of-use rates and standby charges and who is, you know, losing and who is winning. That's for non-participants.

But having said that. If you look at the California societal you will find about 90 percent of the items are there, they are a combination of both. The only things missing are the cost of the incentives. You know, one side pays and the other side gets it. And the standby charges because one side pays it and the other side says yeah, we got a standby charge but it is not enough.

If you have nice complication like time-of-use rates, you know. How you value it. What is the avoided cost of the time-of-use rate. Time-of-use rates or not. Another customer has something which is flat rates. These questions, they drop out, okay, in our report. And we will be happy considering the time constraints. That's up to you. But from my perspective we can write these disclaimers or exclusion statements. We ended up that those are the things that --

MR. McCARTNEY: Right. Is it possible to run the numbers for the other tests while you are doing this? I mean, I was --

I also have to say that the PG&E spokesperson's comment that were made earlier, I just would like to give a resounding second to everything she said. I'm sorry she is not in the room right -- Oh, you're back. Excellent, great job.

I was involved in that. You mentioned the DG report or the Proposed Decision that went out several years ago. I was around at the PUC when that went out and I was very concerned that that was even issued. And I reviewed the draft Itron report at the time and it was, it was lacking in a lot of areas and it's too bad that PD even went out.

But I guess having, you know, seeing this progress for awhile it would be nice to kind of run the numbers in a more comprehensive manner and look at all the perspectives and sort of let the decision-makers weigh all the data.

DR. EL-GASSEIR: Definitely. If you want to design a good program you want to look at the participants and non-participants in detail.

MR. McCARTNEY: Right.

DR. EL-GASSEIR: Because there is that transfer there. And you could that, yes. It just takes time, it is not difficult.

DR. SHEEHY: Right. Thank you for that last comment, Mohamed, it just takes time. So based on our time constraints. Originally this was a project that was slotted for eight months. So that was truncated by various delays by three months and then deadlines were moved forward.

So basically yes, I agree with you. But it was, our scope was determined as societal based on time constraints. And we can parse out, we can take into consideration Susan Buller's comments from PG&E and what you have to say and parse out participant and non-participant benefits as best as possible. But not at this, not to the detriment of the rest of the report. I mean, that's the constraint we are dealing with.

MR. McCARTNEY: Right.

DR. SHEEHY: Today is September 3. And on September 16 I have to hand my contract manager over here a report. So yes, we can consider those but we also ask for consideration of the time constraints. And really what is almost more important here, which we have stressed in the attachments and in the presentations, is that it is the approach. If we can get the approach correct then anything moving forward will be better. And I think that alludes to what Susan was saying.

If we can draw this road map, to borrow her terminology, or if we can create this, an approach that is transparent and people can understand. Even if we can't delineate between ratepayer, participant, non-participant, societal, based on our time constraints, our ultimate goal however is to say, all right, this is how a self-generation program should be evaluated and these are our results based on our timeline.

MR. McCARTNEY: Okay. It would also be informative to get maybe a little more information or some other cites on the avoided damages definition. I guess, will that be in the final report?

DR. SHEEHY: What the term damage cost means?

MR. McCARTNEY: Right, right, right.
DR. SHEEHY: Sure.
MR. McCARTNEY: Okay.
DR. SHEEHY: We can provide that. I mean, those are -- The definitions in that attachment are based -- I mean, these are based on EPA definitions. We didn't make -- That's where these come from.
MR. McCARTNEY: Okay.
DR. SHEEHY: Damage cost.
MR. McCARTNEY: I just didn't see a cite to that. Maybe I missed it.
DR. SHEEHY: Yes, it's the Office of Air Quality and Planning.
MR. McCARTNEY: Okay.
DR. SHEEHY: Yes, OAQP.
MR. McCARTNEY: All right. Thank you very much.
DR. EL-GASSEIR: Any other questions, please?
MR. SOLT: Chuck Solt from California On-Site Generation.
DR. SHEEHY: Yes.
MR. SOLT: There is an SGIP cost benefit analysis being performed right now, I believe, by

the PUC under R-0803-008. I was wondering how these two efforts are coordinated or segregated or whatever.

DR. SHEEHY: Can you specify the report a little bit better. So PUC I believe -- I don't know the specifics of this but I think the PUC is charged -- Itron was the metering and evaluation contract to update its cost-effectiveness evaluation. Is that true? That is my understanding from the SGIP working group. I don't know if that is the exact title. But no, that is not our -- We are -- Our scope is defined by AB 2778, that's it. It is not --

DR. EL-GASSEIR: He is asking whether there is any communication or exchange of information.

DR. SHEEHY: No.

DR. EL-GASSEIR: There isn't. None.

DR. SHEEHY: We have worked with the PUC to obtain data and they are aware of everything we are doing. Sachu is here, he can answer any of your questions about what the PUC does. If you have something to add, Sachu, go ahead.

MR. CONSTANTINE: Sachu Constantine from the CPUC. Just to put it in some context.

There's two things going on. There are two M&E efforts going on at the CPUC. One is the SGIP through the SGIP working group and their contract with Itron and some other subcontractors. That's what you are referring to.

MR. SOLT: Okay.

MR. CONSTANTINE: And there is an ongoing effort to expand that and continue it over the next few years. Under 0803-008 there is also an M&E plan for the CSI program, which has been released. That is a plan that doesn't address the methodological questions that we are talking about here.

There is a separate proceeding. Well, the same proceeding but a separate path that we are moving along with the methodology for cost benefit analysis with the DG programs at the CPUC. That proceeding is still in the deliberative stage so there's not really an outcome there. We have been communicating with the CEC and with TIAX and with everyone to try to make sure that what we get out of this is comparable and applicable to what we are going to come up with eventually.

And of course ours is going to be based largely on the SPM. We are somewhat more bounded by that or constrained by the SPM, perhaps than you are. But our hope is that we are going to get an apples to apples comparison down the road. The question will be really over inputs and not so much about methodology.

DR. SHEEHY: Yes, I agree with that. Do people call in with questions?

MS. MacDONALD: Thank you. I do have a call, a person on the phone. Peter Evans from New Power Technologies is on the phone.

DR. EL-GASSEIR: Peter.

MS. MacDONALD: Peter, go ahead.

Okay, perhaps we will hear from Peter in written comments. I know he was on earlier and he wanted to comment on locational benefits. He is actually currently doing work with Southern California Edison right now on modeling and identifying locational benefits of DR on the grid.

So is there anyone else who has comments about any of the presentations?

Oh, okay. Peter, go ahead.

MR. EVANS: Sorry about that. So am I on?

MS. MacDONALD: Yes, go ahead.

MR. EVANS: Okay. This is Peter Evans.

I am a contractor through PIER and we have been looking at locational impacts of distributed generation for quite a number of years. So I wanted to offer a couple of comments.

First of all, congratulations to all of the consultants. Hopefully you guys will post the PowerPoints because there was something that wasn't in the paper that was quite interesting. And it looks like you are in good shape to complete this report on schedule.

So my comments really are related to the approach and road map part of this as opposed to the distinct or specific analysis. Because I think what you are going to do is what you are going to do with what you have.

My key point that I wanted to make is that through work funded by the Energy Commission, the rifle approach, as distinct from the shotgun approach, for looking at grid impacts of distributed resources actually has been generated. And I hope the approach and road map portion of this report will address this.

That is that the great impacts of distributed generation are highly localized. There may be individual projects even on the same circuit that have very different levels of benefits. We really can't generalize about these projects, we have to do the analysis.

To illustrate. If you have a 200 kilowatt combined heat and power project that is incremented or decremented in the California system, that is not going to change the dispatch order in a GE MAPS model. But it might very well have a big impact on local voltage losses or loading on that circuit. So you have to do a detailed analysis looking at the distribution in order to assess the impacts on the distribution part of the grid.

Another point is that just because a unit hasn't been targeted for grid benefits, that doesn't mean that there aren't high value benefits or high value projects out there. In our work we have gone and looked at existing projects and found that sure enough there's some projects that really don't do much but there are also some projects that just out of good luck have very significant local grid benefits.

And I guess the over-arching comment that I have and the reason I bring these things up is because identifying and incenting high DR units that have high impact in terms of distribution grid benefits remains a policy opportunity for the state.

And as you look at the future of SGIP one of the things that I guess I'd like to see happen is that the program is redesigned to specifically incent projects that are known to have measurable, local distribution grid benefits. And with the techniques that the Energy Commission has funded and that have been demonstrated, it is possible to identify those benefits and to quantify them. And that could be incorporated as a policy matter in a future incarnation of SGIP. So those are my comments.

DR. EL-GASSEIR: Thank you.

MS. MacDONALD: Okay, so do I have any more comments?

Thank you, Peter. No more comments from anyone.

I'll go ahead and wrap up the day with a couple more thoughts. Once again thank you for everyone coming out. I know this issue, the SGIP as well a distributed generation as a whole has been an ongoing issue at the Commission, with the CPUC, and this effort has gone forward. So I appreciate everyone, all stakeholders' presence and participation.

A note on Susan's comment. This is the report. The report is the report that AB 2778 specifically within their scope said it doesn't require a road map. However, I am very familiar with road maps as a Commission person. And it was interesting when you said that. Like a little gong went off.

In working with this report and incorporating this report into the IEPR chapter that I am working on -- Perhaps this isn't the place to talk about the IEPR chapter but this report is going to be part of the IEPR chapter.

So it was kind of a thought I had which is, I wonder if a road map would be helpful in looking at the '07. The road maps have been consistent in the '05 and '07 IEPR and they are used Commission-wide.

So it might not necessarily -- I don't know if we have the time nor is it in the scope for this particular project, but on a whole or carry-on with additional work I think it is a very valid point. And I appreciate your input on that because it is something on our side as well that we are very fond of, a road map.

So just to end the day I want to thank everybody for coming. Final comments for this workshop is on the 5th.

But again, the actual draft report will be out by the 18th. There will be a link within the IEPR on the 18th and then you can comment further for that.

And then we have the IEPR workshop October 9. So there will be still sort of more follow-on through those, those means in regards to this report.

Thank you.

(Whereupon, at 3:45 p.m., the Joint Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of September, 2008.