BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:	)
	) Docket No. 09-IEP-IH
Preparation of the 2009	)
Integrated Energy Policy Report	)
(2009 IEPR)	)

COMMITTEE WORKSHOP ON COMBINED HEAT AND POWER

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

THURSDAY, JULY 23, 2009

9:00 A.M.

Reported by:
Peter Petty CER**D-493

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

Laurie ten Hope, His Advisor

Susan Brown, Advisor to Vice Chair James D. Boyd

STAFF PRESENT

Suzanne Korosec, IEPR Lead
Linda Kelly
Art Soinski
Pramod Kulkarni
Avtar Bining

ALSO PRESENT

Presenters

Ken Darrow, ICF International
Tim Lipman, UC Berkeley
Michael Stadler, Lawrence Berkeley National Laboratory (LBNL)
Evelyn Kahl, Western States Petroleum Association (WSPA)
Michael Colvin, California Public Utilities Commission (CPUC)
Mark Rawson, Sacramento Municipal Utilities District (SMUD)
Bob Marshall, Plumas Sierra Rural Electric Cooperative
Rod Schwass, Burns & McDonnell
David Schnaars, Environmental Strategies, Solar Turbines
Mark McDannel, Los Angeles County Sanitation District
Kathleen Ave, SMUD

Panelists

Eric Wong, Cummins
Jeff Cox, Fuel Cell Energy (Molten Carbonate Fuel Cells)
Bill Martini, Tecogen
Cheri Chastain, Sierra Nevada Brewery
Gordon R. Watson, Hitachi Global Storage Technologies, Inc.

Via Webex

Public

Curtis Seymour, California Public Utilities Commission
Marci Burgdorf, Southern California Edison
Barbara Barkovich, Barkovich & Yap, Inc.
Beth Vaughan, California Cogeneration Council (CCC)
John Redding, Arcturus Energy Consulting, Inc.
Ray Williams, Pacific Gas and Electric (PG&E)
Bob Nickeson, Alzeta Corp.
Patrick McCoy, CA Dept of General Services (DGS)

I N D E X

P R O C E E D I N G S

JULY 23, 2009 9:06 a.m.

MS. KOROSEC: Good morning, everyone. I am Suzanne Korosec. I lead the Energy Commission's Integrated Energy Policy Report Unit. Welcome to today's Committee Workshop on Combined Heat and Power issues. We have a very full agenda today, so I will keep my comments brief. Just a few housekeeping items before we get started. The restrooms are out the double doors and to your left, out in the atrium. There is a snack room on the second floor at the top of the stairs, under the white awning. And if there is an emergency and we need to evaluate the building, please follow the staff out the door to the park that is diagonal from the building, Roosevelt Park, and wait there for the all clear signal.

Today's workshop is being broadcast through our WebEx conferencing system and we do want to remind parties we are recording the workshop. We will make the recording available on our website immediately after the workshop and then we will post the transcript in about two weeks when it becomes available.

For presenters and commenters, I want to remind you to please speak very closely into the microphone so that those listening in on the WebEx will be able to hear your comments and questions clearly. During the Q&A comment periods, we will hear first from folks in the room, and then we will hear from the WebEx participants. And for those of you who are listening in on WebEx, if you wish to ask a question, please send that question to the WebEx Coordinator via the chat function and, then, during the public comment periods, we will also open the phone lines for anybody who wishes to speak at more length. For parties in the room that wish to speak, please come up to the podium in the center of the room and speak into the microphone there, and it is also helpful if you can remember to give the Court Reporter your business card, so we make sure that your name and affiliation are captured correctly in our transcript. I will also just note that written comments are also due on August 6th by 5:00 p.m.

So today's workshop is being held as part of the 2009 Integrated Energy Policy Report proceeding, or IEPR. The Energy Commission prepares this report every two years and covers energy trends that are facing the state and the energy markets, and what energy policies are needed to help us meet our energy-related goals. The purpose of today's workshop is to discuss the new assessment of technical and market opportunities for Combined Heat and Power and Combined Cooling, Heating and Power in California. This will be an update to our last assessment which was done in the 2005 IEPR. And this is really an essential activity given the aggressive CHP goals that are contained in the ARB's AB 32 Scoping Plan. We need to be looking at current economic and regulatory conditions in this updated assessment so we know where to focus our efforts to overcome the barriers to developing the new facilities that will be needed to meet those aggressive goals. So with that very brief introduction, I will turn it over to Commissioner Byron for opening comments.

COMMISSIONER BYRON: Thank you, Ms. Korosec. You look like you have turned a little bit there since the previous workshop.

MS. KOROSEC: Just trying to switch things up for you.

COMMISSIONER BYRON: Good. I would like to welcome everyone. Thank you for being here this morning. My name is Jeff Byron and I chair the Integrated Energy Policy Report Committee, along with my Associate Member, Vice Chairman Boyd, who unfortunately is not here today. He is elsewhere in the state talking about other important issues. However, with us is his Senior Advisor, Ms. Susan Brown. And I understand, Susan, this may be the last IEPR Workshop before you retire from this Commission.

MS. BROWN: It is.

COMMISSIONER BYRON: Well, would you like to say something?

MS. BROWN: No. I am very interested in this topic and I am very interested to retire. It is so nice to see a full house on the topic as important as Combined Heat and Power Distributed Generation. Thanks.

COMMISSIONER BYRON: I do not know how he or we are going to survive without you. Also with us is my advisor, Ms. Laurie ten Hope, who I hope will not be retiring any time soon.

MS. TEN HOPE: No plans.

COMMISSIONER BYRON: I would like to take a second and just remind everyone the purpose of the workshop, and if you will allow me, I am just going to briefly read a couple sentences because I think it is important. The purpose is to present and discuss a new assessment of the tactical and market opportunities for CHP and Combined Cooling, Heating and Power in California, another new acronym, CCHP. The current and future state of CCHP in California is a topic of a number of proceedings, plans and activities at this Commission, the PUC, and the Air Resources Board.

Since we have not done an assessment for a long time on this topic, it is time that we do so. There seems to be a great deal of interest in this topic by the number of folks that are in attendance today. I follow the topic closely. I note that there has been a lot of recent interest and what I would characterize as positioning and, of course, there are a number of pieces of key legislation that have gone into effect recently, as well as are pending around this subject. This Commission has a long record of supporting and promoting the benefits and the need for Combined Heat and Power in previous Integrated Energy Policy Reports. We know there are environmental benefits, there are benefits for customers, there are economic benefits; there only seems to be a limited number of constituents that do not feel that they benefit from Combined Heat and Power.

So despite this continual impasse, I am interested in the facts and the information that you are all here today to present to this Commission that will assist this Commission in making good recommendations, but also in setting good energy policy. So we have a full agenda, lots of material to go through. We want to hear from everyone that is interested in speaking. And hopefully we will keep us on time. And, with that, Ms. Kelly, will you please go ahead and begin?

MS. KELLY: Thank you. Good morning, everyone. I think with Suzanne and Commissioner Byron, we have gotten a general view of --

COMMISSIONER BYRON: Please go ahead and put the microphone right in front of you.

MS. KELLY: -- a general background of CHP and the Energy Commission in California. The Energy Commission has really, from the beginning of 2000, has really focused on CHP and indicated and found in assessments that CHP is clearly an efficient, beneficial resource in the portfolio of energy resources in California. So it started in the 2005 IEPR, as Commissioner Byron mentioned. We did an assessment that really focused on industrial CHP, and we found that the potential for that was significant and that was encouraged in that IEPR, the 2005 IEPR. But we also recognized there were barriers and those were articulated in the 2005 IEPR.

In the 2007 IEPR, we recognized those barriers continued to exist, but continued to support the role of CHP in California's energy portfolio. Then, in December of 2008, after significant hearings and workshops, the ARB adopted their Scoping Study, Scoping Plan, and in that Scoping Plan, they had a target of 4,000 megawatts of CHP that would displace 30,000 Gigawatt hours of demand from other power generation resources. And the calculation was that that displacement would reduce CO_2 by 6.7 million metric tons.

CHP development has really been slow in the state, and it was time to do another assessment. The 2005 assessment was a good beginning to look at what the potential could be, but we knew that it was time to do another assessment to support the ARB goal for CHP. The objective of this workshop is to really get agreement on these assumptions to be used in the CHP Technical and Market Forecast. There are going to be two aspects of this that I would just draw everybody's attention to, the technical, which is still substantial for California, and the market forecast, which, in this new assessment, shows less potential, but that is really a function of the market barriers that are there. We also want to understand what the policy actions and regulatory changes and business models will assure that the greenhouse gas emission and reduction goals for CHP in the ARB Scoping Plan are achieved. I think the key issue there to look at is, you know, what are the regulatory changes in business models. I think that the market mechanisms you will see from the assessment, they can make some differences, but it appears that even market mechanisms, now, will not really support a large potential of CHP in the state.

As we go through the day, I want to suggest a few questions and a few items for you to think about as you hear presentations and in your public comments here, or your questions, or in your comments that you file after the workshop is done. One of them was, you know, we like to have discussions and get your comments on the assumptions in this assessment, the results and conclusions of both the technical and market assessment, of the ICF Report. There will be a second assessment, as well, or a modeling exercise, that is done by Lawrence Berkeley National Labs, and this looks at just commercial. And this is an important new aspect to our assessment. We really are interested in looking at the commercial CHP sector; the 2005, again, just looked at the industrial, so now we want to take a look at the potential for the commercial sector. We think there is a potential there and we think, as you develop CHP in California, it will be a combination of large CHP and small CHP. We also would like to see what changes will be necessary to get the large CHP installed in California. What needs to be done? What marked changes, what regulatory changes, we would like to understand what it will take to get large CHP built in California. We also would like to then see what actions will need to be done to get the small CHP market stimulated. It is a different group of people, and so what it will take to get people to install two, four, or 500 KW CHP systems will be entirely different. But we do not want to overlook that sector, and we want to get your input as to where that potential is.

Next, we want to look at what are the solutions to these barriers. We have been dealing with them for years. And they have been identified in previous IEPRs -- the departing load charges, locational pricing is another key issue that I think has to be dealt with if we are going to realize the potential in California. Access to wholesale and retail markets. These are all issues that have been articulated before, and we would like to deal with them as we go forward to try to support the ARB AB 32 goals.

And finally, one of the last things -- and we understand this is a challenge -- what will make CHP attractive to utilities? During the day today, you will hear from some publicly owned utilities, but we understand that CHP for utilities is always a challenge. There are revenue losses and I think we need to begin to deal with those issues and see, is there a way we can make CHP attractive to utilities and get some dialogue in that area.

So that is a general focus for the day, the objectives. We are definitely looking at supporting AB 32. We are looking at understanding what amount of CHP makes sense so that ARB can look at the number they have and make sure that is a number that is achievable, and if it needs to be adjusted.

So with that, I think we will start with the first presentation. The first presentation is from Ken Darrow. Ken Darrow is with ICF. Ken participated in the first 2005 Industrial Assessment of CHP in California. He and his team were part of that effort. He has done a lot of work in this area, has worked -- he is working with SMUD, he has worked with DOE, and other agencies throughout the United States.

So he is certainly somebody who has experience and expertise in this area. Ken?

MR. DARROW: Thank you, Linda. I want to thank the Commissioners for the opportunity to speak to you today about our work. I guess it is a left click, right click, oh, the down arrow, all right. So I will just start right in. Because of that excellent introduction, I do not need to say any more about what we did in 2005 and what we did this time.

These are the topics, or the game plan for the talk today and the discussion plan. I think, because I have a lot of material and a limited amount of time, this will just serve as a record; I am not going to read through it. We will just jump into it. But there are some things I want to point out. First of all, there are reference slides in the back of the presentation, but they were not printed in the paper copies on the table. They are in the back of the material that is, I believe, posted on the website, and that has a lot more detail on some of the assumptions, and also, whenever we use graphics, there should be actual tables in the reference that show the numbers, instead of just trying to have to figure it from the graphs. And we are all kind of a close-knit community, but there are a lot of acronyms, and so there is a glossary in back, as well, if people -- if I start getting acronym crazy.

So Linda talked about a lot of this, but just describing the current landscape, what is driving the policy today, and it is definitely the issue of greenhouse gas emissions and the AB 32 commitment to reducing those emissions. And the goal that ARB has come up in the Climate Change Scoping Plan was 4,000 Megawatts of CHP, producing 30,000 GWh hours, and avoiding 6.7 million metric tons of CO_2 emissions. And this would all happen by 2020. And so this line in the sand has created opportunity and also somewhat of a panic to try to get at the issues and start the ball rolling so that this can be made to happen. And while the focus is on new CHP, I think another important issue is that there is approximately 6,000 megawatts of contracted QF CHP power in the market, and the continued existence and viability of this power is in itself an issue that needs to be addressed. The next issue that is important is the implementation of the AB 1613, which is designed to create an economic mechanism for export of power from CHP projects to the Grid, and these are for systems that are less than 20 Megawatts, similar to the system that is in place for the renewable energy. The Small Generation Incentive Program has been canceled for non-fuel cell CHP technologies, but there is discussion and SB 412 Kehoe, in terms of reinstating these incentives to promote distributed generation and CHP. And the final aspect of the landscape is the economic downturn that has occurred in the last eight months, and this has reduced economic opportunities, it has made industrial and commercial businesses leery of investing in things, but it has also brought about some very low gas prices, so there is good and bad. Those are the background issues.

I want to spend a little time talking about the ICF CHP Market Model. It is basically a fairly simple engineering and economic calculation, where we try to compete Combined Heat and Power in an application and see how it pays back against the delivered prices. So, to do that, we had a lot of data needs and we look at this in a lot of different individual markets. So the different aspects are the application databases that we have to try to identify the target customers, estimate their electricity and thermal use, and in the appropriate markets, air-conditioning applications. And then, on the price side, look at what the gas and electric prices are now, what they might be in the future, and use that information, together with the information on the technologies, themselves. We have about 12 individual CHP technologies covering the range of available systems and sizes that we compete. And so basically all of this data is segmented into individual markets by size and load factor, and application, and we are competing the individual CHP technologies to see what the economic payback is for that hypothetical customer -- set of customers. And based on that payback, we estimate a market acceptance, or what percent of those customers would accept that payback, and then at what rate would that accepted amount enter the market. That is basically the crux of what we are doing. And in that way, we can run a number of cases, change assumptions either about prices, about technologies, about incentives, and come up with a different look at where the market might go.

So in a lot of this, I have got pictures, and then I have got Word slides, and I am talking over the pictures, and I am saying the same thing that is in the Word slide, so I am going to skip over this one, but it is basically what I just said.

We want to look, first, at the existing CHP in California. It is really one of the most prolific states in the country in terms of the amount of CHP and the diversity of CHP. We maintain a database for the Department of Energy in the entire U.S.; in the California portion we have almost 1,200 sites and over 9,000 Megawatts of power. Now, there are some discretions about, well, is it 9,000, or is it 8,000? And that may be an issue, but the rest of the slides I am going to show on the existing are based on our numbers, and I think they are designed to show where the markets are, what the big markets are, and show the trends, or show the market segmentation.

So in terms of the large segmentation, the largest share of existing CHP is in the industrial market, just about half of it, and then about a third is in the enhanced oil recovery fields because of the large steam requirements that they have for producing heavy oil. So, together, those two sectors produce over three-quarters of the existing CHP. There is about 1,700 Megawatts in the commercial sector and some of that is also fairly bit stuff in universities and the like, and then a small amount that is in the mining and agriculture sector.

Well, looking at the industrial, it is also concentrated in a few large process industries -- food processing and refining make up more than half of the total, and other process industries like chemicals, paper, and wood products. The paper industry, wood products, that is really an historical market for CHP. A lot of that is biomass and waste based production and the rest of these markets are primarily a natural gas production.

And in the commercial market, which again is a much smaller segment, but as we get into our analysis, it is a much larger future potential than industrial. And maybe I should explain that. Industrial is such a good market for CHP that it has had a much higher rate of penetration and it has a higher saturation of existing sites already have CHP. But in the commercial sector, again, these kind of applications -- and I will not discuss every one -- but we are looking for, or what the market likes, is high electric load factor, facilities that operate 24 hours a day, facilities like hospitals and universities and prisons that have a lot of water, heating, and space heating. And then this little segment here -- or, not little, but the water treatment sector, that is the anaerobic digestion market, there is going to be an entire session on that this afternoon. Our model is basically a facility and building-type model and we are looking at natural gas CHP. So for the rest of what we are talking about, we are not including this sector. But that is being addressed separately.

This just shows that the concentration of existing CHP by the utilities and they really reflect the compared size of the utilities, although PG&E has more -- a higher share of CHP to its size than the other utilities. I do not think I want to say too much more about that. But it brings to what I want to talk about, which is that large systems, QF power, is a significant share of the existing CHP. And these numbers in this table reflect the big three and investor-owned utilities, and it is about 5,600 Megawatts of CHP and biomass power that is under contract with the three IOUs. And that was from the latest semi-annual QF status reports. The CPUC has information on their website that shows the comparison of what makes up the generation costs of each of the major utilities, and QF power makes up a third of PG&E's cost of generation already, and 28 percent for Edison. So it is a very important market.

Before I leave the existing markets, I was looking at the years in which these systems went in, and I want to talk just briefly -- I do not have the slide, but what is possible and what is likely. If you look at the biggest years for CHP penetration in California, it was right after the PURPA in the late '70s and the implementation of standard offers, and between '82 and '92, that 11 year period, over 6,000 Megawatts of CHP power went into the market, that is fully 50 percent higher than the ARB goal for the next 11 years. So that, in a sense, you can look at that and say that is what is possible. You have to also look at it and ask what is likely. If you look at the last five years of market penetration for CHP, it is about 250 Megawatts, so at that rate, in an 11-year period, you are only going to get 500 or 600 Megawatts. Basically, that is the future if nothing is done. So that is a range of futures that is about 10:1 in terms of what is possible and what is likely if nothing is done.

So once we finished analyzing the existing potential, that provides a basis for looking at the target markets, or the technical potential. I am not sure if I am being picked up. Can everyone hear me? And so the purpose of this is to identify the target markets, evaluate the electric and thermal use, and identify the likely operating characteristics and configurations so that we can group these into a series of market segments and analyze them together. I like to think of this as, this is the marketing department coming up with the leads, these are the leads that you give to the salesmen, this is not iron in the ground, these are potential, someone has to go and convince these people, these business owners and operators, that CHP makes sense, they have to show what the economics are, and so it is a big process between something being a target and something actually being a project that is underway.

So I am just going to summarize the results. There is a lot more detail on the individual market segments that make this potential up in the reference slides. But the summary is a total of about 18,000 Megawatts. The largest share is in industrial on-site, and then the commercial on-site, and then we split up the potential export market for the current focus of AB 1613, less than 20 megawatts, and then a larger potential export market of greater than 20 Megawatts. And so we hope that the existing facilities, using a number of databases, which again are described in the reference section, but we also made a number of personal contacts and discuss some of these estimates, particularly at the large end, where you have a few small -- a small number of large potential generators.

So those were the target markets, the market leads. And now we are looking at the energy price assumptions that we made. And, again, this slide describes what I am going to say over the next couple of slides on the graph, so I am just going to go right to the graphs, but afterwards you can look back at the Word slides and see what I said. First of all, we discussed what natural gas forecasts we should use with the Commission, and with the Forecasting Group, and we decided to use the latest Energy Information Administration Forecast, which was done in April and it is called their Stimulus Case. It is part of their Annual Energy Outlook for 2009, and because it was the latest work that they had done, it also had -- you can see the early years, it had, I think, correctly reflected, that gas prices are low now. The other line in the chart, the red line, is the price forecast that we used in the 2005 study, and you can see that the market environment now, at least in terms of gas prices, is much more favorable than it was four or five years ago. But I think that, in the long-term, as you go out towards the end of the scenario, there is kind of a convergence in terms of what long-term gas markets will look like. But in the next 10, 15 years, 10 or

11 years, certainly within the time period of the ARB goal, the gas prices are forecast to be fairly attractive. This price, I should say, is the California electric power generation price from the EIA Model, and this was used as a basis for defining the CHP tariffs which get an incentive price. And additional costs for blower fuel (phonetic) was an additional mark-up of around 20 million Btu's.

Then we analyzed the retail electric prices for five major utilities shown here, and the blue lines are retail prices that would be applicable to customers in the 50 to 500 Kilowatt size range. This is one of the size ranges in our model. We also have 500 to a one-megawatt, 1:5 megawatts, 1:20, and over 20. So we looked at all those five size ranges to come up with retail prices. And these prices, I should say, are for a flat slice. This is not a customer that has ups and downs, seasonal, daily, this is if he used a constant amount of power all through the year, with the time of use rates, what would your rate be. And the reason we chose that is because that is basically how we are intending the CHP systems to operate. They are going to run a flat slice, continuously, and then that is what they are going to remove from the load. So the blue lines represent the retail prices and the red lines represent after you have operated CHP, you are going to have some residual of power cost to the utilities. And so the red is what you are stating. And the difference between the blue and the red are the unavoidable cost, the non-bypassible charges, customer charges that you still have to pay, additional meter charges, plus CHP systems do not -- I mean, they do not operate every single minute of the year; they need to go down for maintenance. Usually, when they are on maintenance, they are timed so that they are not on peak, but they also break down, so if they go down on peak, you are going to incur demand charges, and we assumed for this that three months out of the year, you are going to go down on peak and incur the demand charges. So that is how we came up with these ranges, and that is about -- depending on the utilities, between one and two cents per Kilowatt hours is the difference between the retail rates and the savings, so that is the unavoidable cost.

In this chart, which at the far left, the points there are basically the blue lines that I just showed you. That is the avoidable cost or the average electric cost savings today. And then we forecast out into the future based on the escalation assumption that the generation component of each of these utility rates would be based on the marginal cost of generation, which we set at a natural gas-fired combined cycle power plant. So, with assumed capital costs and non-fuel O&M and then the price track that we had for the electric power generation gas cost, we used then -- and so the rates were built up. We assumed that the T&D component of the rates was constant in real terms. And that is how we built up the rates.

We looked essentially at three different versions, not only at a flat slice. This chart is for PG&E. It seems like there is a ghost image there, but this is PG&E, and this is the slightly larger 500:1,000 Kilowatts, and the dark line at the bottom is this continuous slice, this base load power, what do you avoid if you operate a CHP system continuously? And then we also looked at markets, commercial markets, where you are not going to be operating continuously, you are going to be operating -- and we call those low-load factor applications -- you might be operating 4,500 hours a year, big box retail, certain facilities that close down. So, in those markets, they are avoiding a different price because they are kind of a peak-centered application, those rates are about 20 percent higher, so they are actually getting a better price, but they are not getting the benefit of operating as many hours a year. And the last price we looked at was an on-peak avoided cooling rate. In this sense, it is the retail rate because the CHP system, when it generates power, it has to pay non-bypassable charges and the like. But when it generates air-conditioning from the thermal energy, that is basically the same as an efficiency measure where you are reducing your consumption. So they are reducing their consumption of on-peak electricity through the use of air-conditioning; and, in the PG&E case, the cost of on-peak electricity is extremely high with the time of use rates. I think the differential for PG&E is higher than the other utilities, and it is lowest for the municipals, but there still is quite a healthy incentive, economic incentive, for avoiding air-conditioning. And so basically, that is what we did. We analyzed the current tariffs, we developed this escalation formula, and we looked at three different load slices, and five different size factors. And the last thing we did was to look at the export pricing and feed-in tariff. The prices are not established yet for CHP, except SMUD has published a feed-in tariff for projects up to 5 Megawatts.

So what we did for the analysis, what we did to date, was we assumed that the other municipals would adopt the SMUD FIT, so the municipal utilities, we took the SMUD CHP FIT, although we assumed that it would be expanded up to 20 Megawatts to make it consistent with AB 1613. And for the IOUs, we basically assumed it would be treated the same as renewable tariff, which, after looking at the renewable tariff structure, if you are providing a flat slice back at the utility, going through all the different, you know, the power is worth more on-peak, worth less off-peak, if you go through all those time periods, and add it all up, you can come out around 95-98 percent of the market price referent. So that is the price we used in the export analysis for AB 1613, it was 95 percent of the current market price referent, which I understand is for the renewable tariff. And we assumed the constant, flat delivery over all time periods, which I think is reasonably accurate.

So that is basically the pricing discussion. The next most important thing is really what you have to offer these customers, what is the product, how good does it perform, how much does it cost, and so we developed a set of CHP technology costs, the performance, the data, those tables are all in reference slides and they are also in a report that we did last year for the Commission, and I was told this morning that that was likely to be published in the next couple of weeks, or put up online, and that is the economic and environmental mapping project that we did last year. But I do not want to talk too much about individual technologies; they vary in terms of what they cost and how efficient electrically they are, and how much and of what quality waste heat you get from there, and also their emissions. But we assumed that all of the systems would meet the NO_x emissions requirement of .07 pounds per Megawatt hour, and I think the most difficult technology in terms of meeting that are the reciprocating engines, but we assumed that the smaller rich burn systems would use three-way catalysts and the larger lean burn would use a selective catalytic reduction, and that, given the thermal credit for CHP, that they would meet that target and they would be allowed to compete in the market. And we also assumed improvements over time in cost and performance based on ongoing RD&D projects at the Commission, at the Department of Energy, and the manufacturer's own development programs.

Before I leave this topic, I just want to say that the cost numbers in the reference section, in the tables, is a national average estimate. Within the model, we applied about an 11 percent multiplier to reflect higher construction costs in California. This is an average for the state, it was highest in the Bay Area, it was about 23 percent in the Bay Area, and lower in other parts of the state. And another thing that we did was we, particularly in the small markets where experience has been limited, and what experience there has been in the SGIP program has shown that some early systems have some pretty high construction costs, and so we put in a market cost adder in the early years of the model on top of that. So the numbers that are in the back are the reference numbers, but we also had the California construction costs multiplier, and then some early market adders to reflect extra costs that you would have in an early adoption market that you would not have later. That more or less describes the three basic data inputs to the model. And I made myself a note that I was half-way through my slides, and I wanted to know where I was on my time. Am I behind? Okay, I can just keep rambling on, I guess.

So those are the three basic and critical data inputs. What are the sites? Where are the sites? What do they look like? How much potential is there? What are the technologies going to give you in use? And, then, what kind of prices are you going to get? And these are the basic inputs to the economic analysis and the evaluation of market acceptance based on the economic performance.

So now I am going to get into the scenarios that we have run. We ran the base case, which we call -- at one point, we were calling it "status quo," it is basically reflective of policies that are in place now, or, in one sense, the AB 1613, just really close to being a done deal. So the base case includes the remnants of the small generation incentive program, in other words, for fuel cells only, the incentives, and the prices that I just talked about, and any export tariffs below 20 Megawatts. We did not assume that there would be any economic market for CHP above 20 Megawatts. So we did not look at that. If you look at just the avoided cost numbers that the utilities are willing to pay for as-delivered CHP, without any kind of contract, it is down in the three and a half cent range, so we did not feel that was economic without the additional firming up of some contracting scenarios. So we did not include the large export.

Then, the next scenario we looked at was a restoration of SGIP, more or less the way it operated before. The incentives were dropped for the other technologies, reciprocating engines, micro-turbines, and small-gas turbines. So we assumed that those incentives would go back in pretty much the same way that they were operated before, although we also included the current extension in which partial incentives are paid for projects on the first three Megawatts for projects up to 5 Megawatts. So that is more or less how we modeled it.

The next scenario we looked at was expanded export, developing a market for the large systems to export power because work that we did last year and also in 2005 showed that this is where a really fairly significant potential exists in terms of Megawatts that could be provided.

The last scenario that we looked at was a scenario where the CHP operator would be given a payment, and in this case it was $50.00 a ton for avoided GHG emissions. And I am going to talk later about how we calculated the avoided GHG emissions. But that was the basis for the scenario.

So now we will get into the base case results forecast. This chart shows the penetration by the major utilities and, then, the rest of the state and other. And it shows that, in the 20-year forecast period that we used, 20 years, that there would be 2.7 Gigawatts of market penetration in the first 20 years. Now, the base case, again, looking at this with another market split in terms of the size, and it shows that, in the new market looking forward, that the largest share of the market penetration is going to be in sizes below 5 Megawatts, what we are all calling distributed generation, and then, in the 5-20 Megawatts, and without an export scenario in the large size, the remaining on-site electrical base potential in the over 20 Megawatt is fairly small.

And these are all shown as just the new market penetration. If you look at it, oh, first I have got one other thing to show. This is basically the same numbers, except I have added another slice, and these are the top -- kind of the tan color is the avoided air-conditioning, and that is not shown on the previous graphs because that is not a generated value, it is not power outage generated; the previous slides were based on the generating capacity of the systems. This is -- the blue and the red there represent the on-site and the export generation from the machines, and the light-colored slice represents the avoided power for air-conditioning that was provided by the system, so you get -- what is written on the slide is 279 Megawatts of avoided air-conditioning capacity. That number should be 267. There was some bouncing around towards the end, and so that does not change the conclusions. Now, the AB 1613 exported amount is a little over 300 Megawatts, and I realize that this is really not the intention or the hope from the program, there was a desire that there would be a much higher penetration from this size range, and maybe there are ways to stimulate it, but in the available customers and the economics of the markets, we did not see it coming out more than this amount.

This is a little -- to just focus on the new penetration, you maybe lose sight of the fact that, of all the CHP that is already out there. So what I did was I took the same forecast number and I graphed it with the existing in place, and assumed that all of that existing would stay in the market. So, in that scenario, you are starting at about 9,000 Megawatts, and you are growing to about 12,000 Megawatts. It more or less puts in perspective how important the existing market is. And this is just an illustrative case that we really do not model the economics of CHP, or predict whether it will stay or go away in our model. But, just for the purpose of the slide, I took out this 5,600 Megawatts of contracted power with the Big Three utilities in the first five-day period, and what happens, then, even with the 3,000 Megawatts of additional new market penetration, you can see that you do not get back to where you started. So this is just an illustrative example of the fact that we are focusing on the new markets and the new penetration, but the existing markets are also extremely important.

I want to move on to the other scenarios we looked at, and I am sorry that the slide is kind of worked out -- I used a tricky technique in PowerPoint to kind of cut off these titles, and apparently they found their way back. But, anyway, this shows the -- basically, I am going to back up a little bit here -- the top of this line here, which includes the on-site, the export, and the air-conditioning, basically the total capacity impact, these are the numbers that are in the slide that I am showing now. So these include the air-conditioning avoided. So basically, the CO_2 payments case is the next line up from the base case on the bottom, the black line with the boxes. And, again, this was based on $50 a ton payment, with the assumptions that we had about both how well the CHP systems operated and what was avoided at the Grid. And the market impact was 244 Megawatts. We were hoping for a little more. And then, the next line up, the red line, was the restore SGIP case, and that provided an additional 500 Megawatts, and that was all from stimulation, I forgot to mention, in the first 10 years. We assumed that program would be restored and last for 10 years. And so it stimulated an additional 500 Megawatts in the market sizes below 5 Megawatts.

In the large export case that we ran, the purple line with the X's, that provided a market impact of 671 additional Megawatts, and we based this on an assumption that they were not getting the fee and tariff price, but they were getting a price that was equivalent to the marginal generation cost of the California Grid, which we asserted was a combined cycle gas-fired generation plant. And those costs were, at the beginning of the period, were around 6.3 cents, and by the end of the forecast were close to 7-8 cents. So, basically, the price we assumed was the marginal cost of a combine cycle power plant.

And the last line at the top was basically, if we combined all three of these measures between the base case and what we are calling the "all in", certainly not all in everything you can think of, it is just all in for these three cases that we ran. And essentially you get a pretty additive response, that all of these measures, they do not compete with each other, they more or less -- each exert a separate positive impact on the market. And so you end up, then, with -- in the all in case -- of about an additional 1,400 Megawatts of market penetration. And so, with the air-conditioning impact, you are up around 4,400 Megawatts at the end of the 20-year forecast period.

We did some other, I guess, mini -- oh, wait, I was basically going through this slide as I was talking through the pictures, so this is essentially the record of what I just said to the graph, so I am going to skip over that. And we also did some other cases, which was the export market sensitivities. We did two of them, basically. We looked at the below 20-Megawatt market, the AB 1613, and came up with what the market would be under a reduced tariff assumption. We were thinking that some people might feel that taking a renewable feed-in tariff was pretty optimistic, and not appropriate, and so we looked at the impact of taking out the portion that, in the SMUD FIT tariff, they explicitly tell you what the difference is between the renewable FIT and the CHP FIT. And it starts out at about 1.5 cents and nominal dollars, goes up to about 2 cents in the next five years of tiered contracts. So we reduced our market price assumption by 1.5 cents per Kilowatt hour, so it more or less takes it out of the 10 cent Kilowatt hour range, 9.5, 10 cents, and brings it down to the 8.5 cent range. And when we did that, the market was reduced by about 250 Megawatts. One of the reasons there is this premium for the renewables is a premium to reflect the value of the voided GHG emissions, so if we reduced the payment to CHP, but then we also added back in $50 a ton payment for what is GHG emission reduction they did achieve, then basically the market is restored. In fact, it is more than restored; it goes up to 330 Megawatts increased. So I think that is interesting if that, if you lower the price, you are going to get less than this 300, but if you then recognize the GHG emission savings in a different fashion, then that part of the market is restored.

We looked at large export and power maximization. In 2005, when we looked at the data for these large systems, and there may be 30 or 40 large industrial facilities that have 70-80 percent of the total technical potential to export power, and these are potentially very large systems, and we made an assumption back then that they would maximize the power component by building a combine cycle plant with an extraction steam turbine, and that would make their power to heat ratio close to 2, basically trying to get as much power generation out of their steam load as possible. And if you do that, the technical potential in this more than 20 Megawatt sizer engine increases from 3,500 Megawatts to 6,000 Megawatts. And the market penetration increases from 671 to a little under 1,000 Megawatts.

I want to just make a statement right here about, well, if you have got 3,500 Megawatts, why did you only get 671 Megawatts of market penetration? And if you then make this change so that you are saying, under a power maximization strategy, the potential might be 6,000, why did the market only pick 1,000? And the reason is that, when we calculated the economics versus what we computed as the competitive contract price, with the costs of systems, the paybacks were running between five and six years. And based on the logic that we used in the model, which was based on a market survey that Priman did in 2005, basically there is a significant amount of discounting of what you would think were socially acceptable economic returns on projects. But in a five or six-year payback, only about 25 percent down to 20 percent of people asked said that they would go forward with a project if that was their economic return. So, since that was the assumed economic return, or calculated, then the market response was only 600 to 1,000 megawatts, and certainly you could argue that the small number of large customers would react differently, they would respond more positively to this economic signal, there would be a higher acceptance rate, and I think we should be thinking about ways to make the risk of CHP investment, particularly, you know, one of these large projects could be over $300 Million, and it is a tremendous risk for these facilities to make that investment in an environment where they are not sure of the returns, of the gas prices, and a lot of different things. So, anyway, that is a little bit off the slide topic.

The next thing we looked at was the GHG emissions savings, the avoided emissions. It was not my intent to go off and pick a different number than what other people were using. I thought we would discuss this within the Commission, and came up with a reasonable approach, and I think it is reasonable, but maybe fairly optimistic about how well the Grid would be performing. But at any rate, we based it on the marginal power supply, which was a mix, and the base load was a mix of existing and proposed new -- or not proposed, but new combine cycle gas-fired power generation, and also mixing in peak load power from a simple cycle gas turbine, particularly when we are looking at air-conditioning. So we looked at three market segments, the base load, which primarily competes against the base load Grid power, and the intermediate load, which is this 4,500 hour peak-centered slice of power, which we assumed, then, a larger share of peaking power would be avoided with that kind of a load factor, and then, finally, the air-conditioning, we assumed, was avoiding peak power generation. So each of those -- and there is another slide which has more detail on the heat rates that we assumed in the back, and so we come up with assumptions in each of those as a blended heat rate, and then, on that, we add in an assumption of line losses. And line losses vary basically, it depends on where you are in the Grid, when you are in the day, what the season is, and so kind of the typically accepted average system line loss is about seven percent, that is true. But if are looking at a base load number, that would be less. So in that sense, we used five percent, and then, for the intermediate, we assumed eight percent, and for the peaking, you are talking about double-digit line losses. So we used 13 percent. This was based on some work we did with the Arizona Utilities and looking at avoided infrastructure investments for CHP. And the resultant estimates give you these factors for each of these markets as to what you avoid. When you look at all of our markets and our scenarios of blended outputs, our average avoided number is about 940 pounds per Megawatt hour, this changes depending on each scenario. As you add different markets with different load factors, the number jumps around a little bit. I do want to say, because I know that there have been some comparisons to the estimates that the ARB made, is that this average number of 940 is about 10 percent lower than what I understand was used in the ARB Climate Change Goals Setting. And that does not sound like much, but we are talking about a difference between CHP and the Grid, so if you take one of these points and move it in 10 percent, you are actually reducing the difference by about

25 or 30 percent, so it seems like a small difference, but it does have a big impact, depending on your assumptions. And this is what the basis is of the cases that we ran and the GHG savings that we are presenting, although I think we are open to discussing using a value that everyone agrees upon, or more people agree upon, for the final work.

So the results of all that, when you put in those savings, these are the cases again, only this time the Y axis is the avoided CO_2 emissions. And by the end of the 20-year forecast period, we are ranging between 2 and 3.2 million metric tons of avoided CO_2 emissions per year. And the large export case actually has the highest CO_2 reduction per added Megawatt, and also the CO_2 payments case, because basically the projects have stimulated that have the best CO_2 signature.

Just to summarize where we are, the new market penetration in the base case for status quo was just under 3,000 Megawatts in 20 years. That includes the air-conditioning impact, or includes the 304 Megawatts of the AB 1613 export, and I do not know why this number keeps changing, but 267 Megawatts of the avoided air-conditioning. And in the policy cases, we are adding 500 potential Megawatts of added by restoring SGIP, putting in a CO_2 payment structure adds 244 Megawatts. The large export case, this is a typo here, it is 671, or, in the power maximization case, possibly close to a thousand. Then, the sum of all the measures, again, that number is a typo, it is 1,408. And the GHG impacts, 2 to 3.2 million metric tons per year. This table was intended to be helpful, but it has caused quite a lot of excitement. But I am comparing our scenarios to the ARB Climate Change Goal of 6.7 million metric tons per year and, in the base case, first of all, our horizon was a little different, so I interpolated the 2020, and the base case, we do not get the market penetration without additional market stimulation. And in the all in case, the all in measures that we looked at, you do come very close and you, in fact, exceed the goal a few years later, but we do not get the same electric output because we are looking at sectors, including sectors in the commercial sector where you are only running 4,500 hours a year. So there is a reduction in the amount of generation that you get per megawatt, and then our avoided CO_2, part of that, was due to the about 10 percent difference in the assumption on avoided emissions, which, as I said, has about a 25 or 30 percent impact reduction than what we ended up with. But the biggest thing I think is that, in order to look at the smaller markets, the commercial markets, we did not assume that all of this thermal energy was going to be utilized. And realistically, in a lot of applications like a hotel, a developer may -- his economic goal may be 70 percent utilization of the thermal energy. It is not always going to be 100 percent. And so we made assumptions in the small sectors up to 5 Megawatts that the thermal utilization would be less than 100 percent; it was 80 percent, and then, in the larger sector, it was 90 -- in the larger sector where you are talking about industrial process industry, we assumed 100 percent. But another thing is, in the cooling markets, you are taking a lot of this thermal energy and you are using it not to replace boiler fuel, you are using it to replace air-conditioning, which, as I showed, is an excellent economic value if you can replace 25 cent, 30 cent electricity with thermal cooling. But thermodynamically, it does not provide the same benefit. It takes a lot of this heat to produce a ton of cooling, and it takes more than a ton of cooling to avoid 1 Kilowatt. So those, I think, are the main differences where we had different load factors in the market, we assumed some of the sectors to be conservative, were not going to achieve 100 percent use of thermal energy, and the cooling markets where we used thermal energy, you get a much lower GHG benefit. That is kind of the reason how we ended up at a lower number. Although, I think when we show, with stimulation, you can stimulate the market and get penetration. And also, if you use the same avoided emissions, our 3.2 number there would probably be a little over 4, or 4.5, something like that, just on the supply side change. So I think we want to look at that before we actually publish the report as to where we are.

This is still wrapping up, but I wanted to kind of do a big vs. small comparison, and this table kind of tracks all the different changes as to whether they affect the big stuff, or the small stuff, and if you look at the existing market, 87 percent of it is big stuff; but now you go down and look at the growth potential, at least in terms of the sectors we looked at and the responses, and 75 percent of it is in this new DG small stuff market. So it is a big shift in the market. And the large CHP and small CHP face entirely different market issues and react to different market stimuli, so you have to really consider them separately. The small CHP reacts to having an economic feed-in tariff, having the SGIP incentives, and also continued improvement in development in the technologies to reduce the cost, reduce the packaging costs, and things like that. Whereas the large CHP basically are interested in the preservation of a large amount of existing contracts, and also facilitation of a system where large systems can contract economically for new power projects, and reduce the risk in that kind of a process.

So, again, I think the greatest immediate, or market, in GHG benefit comes from preserving the existing large CHP, and then pursuing remaining large CHP technical potential. In the small CHP area, that is the largest emerging market, so I think that is also very important. In the base case, it is really 90 percent of the market penetration is below 20 Megawatts. If you facilitate large export, then that percentage goes down. But the small CHP has additional benefits that were not modeled, so I am more or less putting these out there gratuitously, they are not the result of our analysis, but they do reduce the need for T&D investments, they increase reliability for the customer and for the system as a whole, or they can if they are designed correctly. And technical innovation, development of economic business opportunities. I think they create opportunities to enhance economic growth in the state and maintain the viability of businesses, as well as help them reduce their greenhouse footprint.

The last thing is just recommendations on the ARB goals. I think I talked quite a bit about that, but basically what I take away is that the purer market forces without stimulation is not going to bring in to that level, so you need to have an aggressive set of measures and policies to help to reduce risk and to create more confidence and develop an ability for the suppliers and the buyers to contract for this power, which is demonstrably more efficient than just producing power alone at the central station, and has a higher economic benefit and higher GHG benefit. And if you look at the era in the early '80s where there were tremendous effort and policies to create incentives or a market for CHP power. Some might say it is too much of an effort, but there were 6,000 Megawatts that responded to that period where there was a tremendous number of incentives. So I think there is a very good possibility that, with the appropriate stimulation, that the targets can be met. It is important to remove barriers and, when I think about barriers from an economic sense, I do not consider something, well, if it is not economic, I do not consider that a barrier, it is just not economic. But there are barriers, I think, that keep economic projects from moving forward and I think one of them is this fact that, in the Priman market research, so many -- there was so much discounting of acceptable projects. Fifty percent of people would reject the two-year payback, 75 percent of people would reject a five-year payback, and 80 percent would reject a six-year payback. This really speaks to risk and lack of information, and so I think there needs to be an effort made to increase awareness, provide information, access to tools to pre-screen for customers so they can figure out whether this might make sense for them, and then ways to reduce project risk in terms of the contracting and pricing, and also in the small side to do demonstrate new technologies, or emerging technologies, so people can see that they work. And then improve the project economic capabilities of the small CHP -- I just said that, actually. And provide direct value for CO_2 reduction.

So I think in the future you are looking at the likelihood of a cap and trade, and that there should be payments for distributed generation, and even large generation in terms of the degree to which they help the state meet the avoided CO_2 emission goals. And then other incentives that would help internalize these other CHP benefits, the T&D support, reliability, peak capacity, and that kind of thing. So, again, there is additional detail and reference slides, and we will be publishing a report over the next month.

MS. KELLY: Thank you, Ken. Commissioner Byron?

COMMISSIONER BYRON: Mr. Darrow, do not go away, please.

MR. DARROW: Sorry.

MS. KELLY: I do just want to just let everybody know that, with regard to a report, after this workshop, we get inputs and suggestions. We have the capability to do some additional scenarios, and that we will be finishing up this report in the next month?

MR. DARROW: Yes.

MS. KELLY: Month. And it will be utilized for the IEPR.

COMMISSIONER BYRON: Mr. Darrow, thank you very much. We are going to try and stay on schedule, so I have gobs of questions, but I am going to narrow it down to basically two. First of all, excellent analysis and report. We have not met, but I am familiar with one of your colleagues, and I am very impressed with the analysis and the national perspective, if you will, that you bring. Where are you from? You are not from California, are you?

MR. DARROW: Um, no. Well, I grew up in Philadelphia --

COMMISSIONER BYRON: No, no, I just mean -- I do not want your whole life story, just where are you based right now?

MR. DARROW: Seattle.

COMMISSIONER BYRON: Where?

MR. DARROW: Seattle.

COMMISSIONER BYRON: Seattle. So you bring an outside perspective that I think is extremely valuable, and I appreciate the analysis that you have done. I want to just ask questions in two key areas, basically the importance of the assumptions, the starting assumptions that you make in this analysis, and a second question around the differences between our ARB Scoping Memo expectations for this sector versus what your results are. You know, if I go all the way back, I did it by page number, so it is page 12, but it is probably about slide 24, where you show that the AB 1613 capacity results in about 300 Megawatts of installed capacity. Of course, this is a dynamic situation right now; AB 1613 has not been settled at the PUC, so it would seem to me that your assumptions there are really key as to how that proceeds. I have been tracking this somewhat closely and we do not need to get into the specifics of what is going on at the Public Utilities Commission in terms of this particular procedure, but isn't it really key what you are assuming there as to how you end up with 300 Megawatts?

MR. DARROW: Yes, and I realize it is a disappointing number compared to what we assumed. And what we assumed, after looking at a lot of commercial applications, is that generally in a commercial facility, you have got more electric use than thermal use, and we did not expect to see any export potential from commercial facilities. We thought this is basically an industrial market where a process industry has available steam, and so we looked at this major industrial plant database and identified plants in the database that has information on their electric requirements and their steam requirements, and from that we developed an estimate of what the technical potential would be to produce CHP and how much of that could be exported. And that was also the basis for the large sector, as well. But if you look at that, the number of facilities that have this excess or additional steam where they could produce power with 100 percent utilization of the thermal energy beyond what their electric needs are, we saw it as fairly limited. Although, when I say "fairly limited," this 300 Megawatts, and I would have to look at the numbers, may reflect only 15 to 20 percent of the technical potential, depending on what the payback would be to them of investing in a project to do this. So the technical potential might be, you know, five times that, 1,500. But the economics in our market, we are fairly heavily discounting it because that is what the market does today. They are very risk adverse in terms of CHP investments because of the environment.

COMMISSIONER BYRON: Good. I appreciate that answer. You know, having tracked what has been going on there, I -- well, let's just say this -- the author of this legislation is a pretty smart guy. When I talked to him a couple weeks -- and he is very preoccupied today, I think there are 20 pieces of legislation that the Assembly needs to get through by tonight if we are going to have a budget. So he is a little preoccupied, but I know he is very interested in this subject, this being one of his pieces of legislation. And I do not think he is going to be very satisfied to see that it is only currently going to produce a small amount of incremental increase in the efficient use of Combined Heat and Power; but nevertheless, thank you for that analysis and thank you for that answer. Let me ask you the other question. The ARB CO_2 goal is substantially higher than the number that you project. That is kind of alarming, I think. Did we calculate it wrong here in the Government or did we over-estimate?

MR. DARROW: In terms of the ARB estimate, we went through it and it seems to me that there were reasonable assumptions on both the supply and the demand side; but, although they were reasonable, they were -- I would think -- the best and very good in just about every area, at least on the CHP side. So the assumption is that you put in these systems and they are all going to be high load factor systems operating all the time, so you are going to get a lot of output, and that your combining electric and thermal efficiency is going to be in the high 70s and you are going to be able to use all this thermal energy, and it is all going to go for avoided boiler fuel. I mean, that is not an impossible future, but it is optimistic. And we look at the market from a disaggregated perspective. And also, one of the goals within distributed generation is to expand the number of applications that can use CHP, and to do that we are looking at markets where you use the thermal energy for cooling. And that has an economic value, but when you take the energy and use it for cooling, you do not end up with the same kinds of overall efficiencies and savings. And the fact that we used different numbers about the power side, or the avoided side, I mean, I wish that was not so, and I would be happy to change our numbers on the central Grid side as to what you avoid, as to what more closely matches with what they did. As far as their CHP assumptions, they are possible, there is nothing wrong with it, but it is a very good system, it is using all of the energy, operating all the time, and it is competing against a central Grid that is maybe a little worse than what we assumed it was going to be.

COMMISSIONER BYRON: If you will hang on for a minute more. Did you have a question? There is five more minutes on the agenda. I am just going to open it up for some quick clarifying questions if anybody from the audience has any. Please come forward and, if you will, just identify yourself.

MR. SEYMOUR: Curtis Seymour from the CPUC. I have a question about the 300 Megawatt number for that AB 1613 potential. It is my understanding that that is the export capacity, and so the actual installed capacity from those facilities would be greater than 300 Megawatts?

MR. DARROW: Yeah. That is an incremental export capacity, although we do not physically keep the facilities together and analyze them facility by facility. We take the export potential and analyze that separately, so I have no way to match it up to the on-site. But it is incremental export.

MR. SEYMOUR: Okay, thank you.

COMMISSIONER BYRON: Mr. Seymour, thanks for being here today. Any others? Please come forward. Ms. Burgdorf and Ms. Barkovich.

MS. BURGDORF: Hi, I am Marci Burgdorf, Southern California Edison. I just wondered if you could clarify the avoided AC that you show on the chart on page -- and you might have answered it toward the end of your presentation -- is the avoided AC your assumption that the thermal output would then provide the cooling? Is that how you are coming up with that avoided AC number?

MR. DARROW: Are you talking about the GHG emissions or the electric price?

MS. BURGDORF: The GHG emissions.

MR. DARROW: Okay.

MS. BURGDORF: On page 29. Slide 29.

MR. DARROW: Slide 29. We basically -- everything is "basically," sorry for that, I need a lesson in public speaking -- the avoided air-conditioning is -- well, the cost value is based on a 2,000 hours, roughly, on-peak. And so we assumed that that would be avoiding a simple cycle peaking gas-fired generator, operating not too terribly well in the heat of the summer, and so we came up with a heat rate that was a little higher, although I have to say, in discussions with some other utility work that we are doing, that there are peaking heat rates that are higher than this. But essentially, we are assuming we are avoiding a gas peaker for the air-conditioning.

MS. BURGDORF: By having CHP system, so it is not --

MR. DARROW: Well, by having the air-conditioning of the CHPs.

MS. BURGDORF: Of the CHPs, okay, thank you.

COMMISSIONER BYRON: Thank you, Ms. Burgdorf. Ms. Barkovich?

MS. BARKOVICH: Thank you. I have some questions about the retail electric price analysis. I think -- I note that you state that you started with current tariffs for the five major electric utilities, but, first of all, there are some anomalies, for example, the [inaudible] between PG&E and Edison is a function of a couple of things that are going to go away next year, so I do not think that is going to continue; secondly, the assumption that T&D costs are fixed in real dollars is not a good assumption, given that there are some major investments in transmission going on right now, some major proposals for increases in distribution costs. Thirdly, I would draw your attention to the fact that the marginal sources of power in the state are going to be renewables, rather than gas-fired combine cycle, and that is going to cause prices to go up. So I would suggest that you may be over-stating the differential between PG&E and Edison and understating the cost drivers for retail rates. There are two studies you could look at, the Nextant Study and the Energy Division Study at the PUC on the 33 percent renewables, that, whereas I think they may be unrealistically low, they will give you some sense of their assumptions about increases. And I understand you had to make some simplifying assumptions here, but it is possible that you may be understating the potential for CHP because of the retail assumptions you have made. So if I get a chance, given everything else that is going on, I will submit some of these comments in writing. I gather they are due on the 6th, but I think there are some things that should be looked at there because they seem to be significant in terms of driving the results. Thank you.

COMMISSIONER BYRON: You know, I think few people would understand these nuances more than Ms. Barkovich here in California. That is a lot to expect from someone from Seattle to understand.

MR. DARROW: That was going to be my answer.

COMMISSIONER BYRON: That is an acceptable answer, Mr. Darrow.

MR. DARROW: No, I appreciate that and, honestly, I feel we are the CHP experts. Please help us with electric utility economics and natural gas supply and GHG avoided costs so we can put them into the model and come up with maybe a better result.

COMMISSIONER BYRON: Good. Thank you, Ms. Barkovich. I am going to suggest that we press on. Mr. Darrow, thank you very much.

MR. DARROW: Thank you. [Applause]

COMMISSIONER BYRON: Next presentation and analysis.

MS. KELLY: Okay, Our next speakers are going to be from Lawrence Berkeley National Lab, Tim Lipman and Michael Stadler. They are going to team on this presentation, as I understand it. And this presentation, we knew that Lawrence Berkeley was doing work with a model they developed looking at commercial CHP. And we also knew that this team, which includes Chris Marnay, has always felt that tariffs can very much influence the adoption of these various technologies. And seeing we were really trying to focus on getting some new information on this emerging commercial market that I think everybody is beginning to recognize, may have much more potential than we thought, we have been partnering with Lawrence Berkeley to do this study. And so this is just an initial study. They found some interesting things about commercial CHP, the effects on tariffs, and I think, most importantly, the relationship between CHP and solar in buildings that I think was something that some of us had not thought about. So, Michael?

MR. LIPMAN: Actually, I am Tim Lipman. That is Michael over there, and he will be with us in a minute. My name is Tim Lipman. I am actually at U.C. Berkeley, down the hill from the Lab. I wear a couple of hats at Berkeley and one of them is co-director of something called the Pacific Region Combined Heat and Power Application Center. And we work closely with the Berkeley Lab on analyses of this kind. Linda mentioned our ring leader is Chris Marnay, who could not be here today. He has the misfortune of being up in Vancouver, but he sends his regrets. And Judy Lai is also here with our Berkeley Lab team. And I am happy to be here to present this stuff. I am going to do a quick overview of the presentation and the study. I am going to do a quick overview of the results and just to highlight some key findings. And then Michael will come up and kind of walk you through quickly, because we do not have a lot of time, how we got these results. And then, time permitting, Linda, it would be nice if I could do a quick overview of the CHP Center at the end and our current status, we will see if we have time for that.

So quickly, the study that we have done here, I think some of the findings are actually broadly consistent with the one that you just heard, but we have a much narrower focus with this study. We are looking only at medium-sized commercial buildings in the size range of 100 Kilowatts to 5 Megawatts of electrical load. So we are only looking at one section of the market, compared to what you just heard.

The general approach is to use something called the CEUS database to get the electrical and thermal loads of the buildings that we analyzed, and this is the best database that we know of that characterizes different commercial buildings and different climate zones within a state. So, having developed a sample of buildings, we then used this DER-CAM model, it is a very powerful model, Michael spent a significant part of his adult life, I think, working on this model at this point, along with Chris Marnay. And it focuses on CHP, but it can also, as Linda mentioned, look at solar in combination with CHP, which can lead to some interesting results. And then, of course, we too are trying to get at the CO_2 result findings that the model produces in terms of how that compares with the ARB

Goals. And what we did was we looked at a reference case, and then some additional cases that involve carbon tariffs and feed-in tariff designs, and we are just really -- I think we should stress -- we are just getting into the feed-in tariffs, we are grappling with this like everyone, we do not know exactly what those feed-in tariffs are going to be, so all we can do is kind of do some "what if" type questions for now.

This is how it looked on my Mac, so it is a little hard to read and I apologize for this. I guess we are having the same problems as the previous speaker. This should say -- the kind of garbled text should say "Installed Capacity," which is the capacity we are looking at compared to the 4 Gigawatt goal, so that should say "Installed Capacity." The next bar is "Electricity Generation," so that is Terawatt hours, Gigawatt hours, whatever measure you want to use, and then the third bar is CO_2 Abatement. So, again, Capacity, Generation, CO_2 Abatement. You can see where benchmarking those to the ARB Goal of 4 Gigawatts, and the reference case, which Michael will explain more carefully, the referenced case does not include feed-in tariffs, it includes a very modest SGIP in 2020 for fuel solids of $500 a Kilowatt, but no other incentives. If you look at what we did, the sector that we looked at was about 35 percent of the commercial sector. So our results were for only that 35 percent -- so kind of keep that in mind, it is very important. And we came up in the reference case with about 1.5 Gigawatts of additional CHP by 2020 in this sector, alone.

The electricity generation results are actually a little more modest than the ARB analysis would suggest because, at this point, they came up earlier; where ARB assumed a fairly -- well, I would say a very optimistic -- capacity factor, 86 percent, we find in our modeling that it is rare that a CHP plant will run that often, based on economics, that it is not always economically favorable to operate that often. We find lower capacity factors and we used the lower capacity factors that we find in the modeling, we end up with somewhat proportionately lower, both electricity generation totals because of the lower capacity factors, and also somewhat lower greenhouse gas emission reductions, and that is an important point, I think we should talk about more today.

Another point, though, is that the cost savings that we get in 2020 from these building is about $190 million per year for this, again, 35 percent of the market -- .2 billion dollars per year saved by these companies. And then, a final point is that most of what we get adopted again, we have a modest incentive for fuel cells here in this 2020 case; still, most of what gets adopted is internal combustion technologies with heat exchange. So, with that, I think we will bring Michael up to take you through all of that a little more carefully in terms of the assumptions and everything, and then, if we have time, I will be back with a quick update on the CHP side.

MR. STADLER: Okay, thanks for having me today here. As you also can hear, I am also not from around here. So you are also getting the outside view. The next 15 minutes, we will briefly talk about the model that we used to get to this reference case, and also talk a little bit about the CEUS database, and then I will give you more insides on the sensitivity runs that we have performed for the feed-in tariffs, and also for carbon taxes.

Okay, the model that we used is the Distributed Energy Resources Custom Adoption Model, and we have been designing this for more than seven years at Lawrence Berkeley National Lab, and this is a very important picture here, and it looks pretty complicated, but the thing is, this is the building as we see it with the different energy flows and the different options that can be used to satisfy the energy needs. So the yellow arrows are electricity flows, the blue ones are natural gas, propane, alternative fuels, and on the right-hand side, you have all the different services in a building like electricity loads, computing, lighting, and then we have the important part of building -- cooling, building heating, and hot water. And, of course, there are different options to satisfy all these needs and, in descent, we have the combined heat and power where we started seven years ago. Most recently, we added electric storage, heat storage, PV and solar thermal, and we really think it needs an integrated approach to model all these different options, and I want to show you this with the building cooling. For example, we can just buy electricity from the Grid and use it in an electric chiller to cool down the building; but, on the other hand, we could also buy natural gas, burn it in a fuel cell, use that electricity to cool down the building in an electric chiller, or we just utilize the waste heat from an internal combustion engines or fuel cell. But, on the other hand, we can also install solar thermal systems and use it in an absorption chiller, for example. Or we can directly burn the natural gas in a direct fired natural gas chiller. So, as you can see, there are a lot of different options, and we really think we need to use an optimization tool to minimize the costs for a building, or we can also minimize the CO_2 emissions.

Most recently, we started working also on the passive side, where we reduced the loads in the building by efficiency measures, and we built new windows, whatever, to reduce the loads, and then, if possible, to meet all these remaining loads by renewable energy sources, for example. So that is the basic for the model that we used. And DER-CAM, as already mentioned, considers multiple technologies, not only CHP; we also model PVs, solar thermal, and storage, if needed. We can minimize the costs for the building for certain test years, which means we also consider the amortized capital costs for investments, or we also can minimize the CO_2 emissions, which is a different strategy.

It is a very bottom-up approach where we consider every single building in detail, and in this way, we built the 35 percent commercial electricity demand that Tim mentioned before, for the state of California. And one important thing is that we also can handle zero net energy buildings which are getting more and more important these days.

As Tim mentioned, we used the CEUS database for our study, and in the CEUS database, we have around 3,000 building types and different climate zones. As you can see here on the left-hand side, this is the State of California with all the 15 different climate zones, and the whole pie here represents the total electricity demand at a commercial sector in California, and the blue parts are not considered in CEUS database because they did not participate in the study, and we also excluded the green one, which is SMUD, because we think it is not that attractive for CHP in the size range that we are considering, and which left us with the red pieces. But the thing is, in CEUS, we have also miscellaneous building types, and it is really hard to model them since we do not know what building type it really is, so we also left them out and, at the end, we considered six to eight percent of the CEUS database in our study. And, as Tim also mentioned, we are most interested in buildings between 100 Kw and 5 Megawatts, so we also took out some buildings from this remaining six to eight percent, and we ended up with 35 percent of the commercial electricity demand in California, which is considered in our study.

And the objective was to estimate this CO_2 potential in 2020 for these medium-sized commercial buildings, and we ended up at 138 buildings in different climate zones which we considered in the optimization, which takes around a day for one sensitivity run.

Now, I want to talk about the results. Before I go to the results, I just want to briefly mention the key assumptions that we made here. And, as already mentioned, we are not only considering CHP use, so we are also taking a closer look to pv and solar thermal, how this interacts with all the CHP systems. Then, the technology costs in 2020 that we are using are based on the assumptions today of annual energy outlook, which means, for fuel cells, with a lifetime of around 10 years, we are in the price range of

$2,200 to $2,800 per kW, with heat exchange. General combustion engines with heat exchanges and a lifetime of 20 years, which are the upper price range here because we also are considering catalytic converters here, we are between $2,200 and $3,600 for kW, and photovoltaic's, the expectation for photovoltaic's in 2020 is around $3,200 per kW. The other thing is, we kept electricity tariffs from the different utilities considered in this study from early 2009 and late 2008 constant and real terms for 2008. And we did the same for natural gas because, currently, well, the last year everything changed because, in 2008, we saw high natural gas prices, then it came down early 2009, so we perform different sensitivity runs and, at the end, we used the natural gas price forecast for 2020, which reflects the average natural gas price between 2006 and 2009, which we used for the 2020 forecast. And for the investments, we used six percent real interest rates for all the equipment that gets installed.

Okay, so for the reference case, we have here the first result and, on the X axis, you see all the different building types that we considered, like lodging, small offices, warehouses, schools, retail stores, restaurants, warehouses which use cooling, large offices, healthcare, groceries, and colleges, and on the Y axis, the total contribution to the CO_2 abatement. And as you can see, the buildings are really different here, and the most attractive buildings are large offices, healthcares, colleges, and also lodging; but most interestingly, most of these buildings are located in climates on 13, which is San Diego Gas and Electric territory, and that is because we have a lot of cooling there, and the tariff seems very favorable to install all these technologies there.

One thing which already came up today is the [inaudible] or the capacity factor, and one thing in DER-CAM is that we are not assuming a certain capacity factor. The capacity factors are a result of the model, and here I will show you for Climate Zone 3, which is PG&E, for large colleges, electricity for a summer day, and as you can see, the red part, which is just internal combustion engine in this case, is not running all day long. During the night, it is not running because we do not have the need for heat, for example, or the tariff -- off-peak tariff -- is not really favorable for this. So we are getting an annual capacity factor of about six to eight percent for this college, which is pretty good. So we can end up between 30 and 80 percent in our results here.

The other interesting finding is, if you check pv and catalytic combustion engine, then you see that those technologies together shade the peak-load here. So afternoon, when the solar radiation goes down, you can see that the internal combustion engine kicks in and goes to the maximum power through its use of on-peak demand charges, or the on-peak related cost from the tariff.

So, we also did some runs for carbon taxes, and here we find an interesting link between pv and solar thermal. We used three different carbon tax levels of $150, $500, and $1,000 per ton of carbon, and on the X axis, you have the carbon tax, and on the Y axis, we have the carbon emission reduction compared to a two nothing [phonetic] case --

COMMISSIONER BYRON: Mr. Stadler, if I may, just because you are not from here, I need to give you a pretty stern warning, we do not use the word "taxes" around here, particularly on a day when we are trying to get a budget solution.

MR. STADLER: Okay, so maybe that is the only tax I propose here. Okay, thanks. The two nothing case (phonetic), which is where we do not install anything, and just to put the generation in pv, solar thermal, CHP systems, so we compare everything to such a two nothing case. We did two different sets of runs where we just had CHP in the solution, which is the red line at the bottom, and then we also did the second set where we considered also pv and solar thermal as a possible option, and as you can see, first of all, we get higher carbon reductions when we have pv and solar thermal in the solution; but, on the other hand, if we exclude it, we also see an increase in capacity on the CHP system side, and we can reduce up to almost nine percent in carbon emission reduction if we just consider CHP systems.

The other thing that we observed is, for the pool line at around $1,000 per ton, we get a saturation in carbon emission reduction, and that is because we are restricted in the possible space for pv and solar thermal systems, which we also can model in DER-CAM, and it looks like that, at these high levels, we already are reaching the maximum allowable footprint for pv and solar thermal systems, and that is also the reason why, at this point, CHP kicks in and makes up for this constraint, I would say.

But the bottom line is that we have to consider all these interactions between CHP, pv, and solar thermal to get, for example, the tariffs, the feed-in tariffs, right.

COMMISSIONER BYRON: Very good.

MR. STADLER: Mentioning feed-in tariffs, as Tim already mentioned, we already started on some cases for feed-in tariffs, and here I want to show you a feed-in tariff which, with a sales tariff, which is exactly the purchased tariff you buy electricity from the Grid. I am not giving any self-gen incentive for technologies here. And, again, we did two different runs where we had CHP, pv, and solar thermal in the solution of only CHP, which are the green bars, and the red bars are CHP, pv, and solar thermal as a possible option. The first thing is, without any self-gen incentive program, we are only getting into combustion engines in this solution. And that is the reason why we are not really good in terms of carbon emission reduction; if we are not considering pv and solar thermal, as you can see on the right-hand side, if we have only CHP, and we have a feed-in tariff, we are ending up with a carbon reduction potential of 1 megaton which is less than the reference case, and that is because we have the internal combustion engines there.

So bottom line is, the feed-in tariff just slightly raises the generation output from CHP systems here, and that is because of the capacity factor problem and 10:1 [inaudible] combustion engine problem. But we also did a run with higher self-gen incentives for fuel cells, and this is pretty interesting, and I compare this here to the reference case, and we gave a self-gen incentive for $1,500 per kW, which is roughly 60 percent of today's level. And, as you can see, this really impacts the results a lot because, compared to the reference case, we can increase the installed capacity in this mid-sized commercial building sizes to 2.9 Gigawatts, and also the output increases to 10 terawatt hours, compared to the reference case of 7.4

terawatt hours. And, of course, since we are using fuel cells, which are more efficient than internal combustion engines, we also can increase the CO_2 abatement potential to 1.8 Megatons in this sector, which considers buildings between 100 kW and 5 Megawatts electric peak loads.

So, the observations are that DER-CAM really delivers very highly variable capacity factors between 30 and 88 percent, which depends on the side and the tariff, and, here, the tariff is real important. And in the reference case, we found an average capacity factor of 55 percent, which is way under the number which was assumed by the Air Resources Board of 86 percent, and that is also the reason why we are so disproportional on the energy production output from CHP systems.

As I have shown, carbon taxes not only drive pv and solar thermal adoption, they also drive the CHP adoption. And, in the reference case, we got 1.5 Gigawatt of additional CHP in this mid-sized commercial sector by 2020, but the highest self-gen incentive case really can increase that potential to numbers around 2.9 Gigawatts. And in future work, we really want to focus on the interaction between feed-in tariffs and maybe self-gen incentive programs just for fuel cells, to make sure that we really can achieve higher CO_2 abatement potentials that I have shown here. And, of course, the interaction between pv, solar thermal, and CHP is pretty important. And I have not talked about this much, but storage technologies. We are not considered electric storage systems here, and this might change the situation because, in other work that we have done, we found that CHP systems and pv support each other. It is not that only pv systems are used to charge batteries, very often batteries are also charged by CHP systems during night hours, or by cheap off-peak electricity. So, in other words, we could increase the capacity factor by adding storage systems, for example. And that is everything I want to talk about the results, and now I want to hand it back to Tim.

MR. LIPMAN: Thank you, Michael, right on time. Well done. Actually, both the presentations this morning were good set-ups for just a few words on the CHP Center. We only have five minutes and I am just going to say a few words. I would be happy to talk with any of you about it later today if you want to learn more about it. We have a couple of our Advisory Board members for the Center here, as well today, too. I will not embarrass them by pointing them out, though.

The CHP Center that I am talking about is called the Pacific Region Combined Heat and Power Application Center. We call it PRAC for short, Pacific RAC, these are called the Regional Application Centers for CHP, or the

RACs, ours is the PRAC. And it has been operated by UC Berkeley, UC Irvine, and San Diego State University since 2005, sponsored by DOE and the California Energy Commission, involvement with lots of other key partners, including Electric and Gas Utilities, the Berkeley Lab, of course, we work closely with on analysis like you have just heard, California Clean DG Coalition, I see Eric Wong back there, who we coordinate with. This is one of eight regional application centers for Combined Heat and Power, sponsored by DOE, it started with one in the Midwest, and then there were five, and now there are eight. Since 2005, we conducted a whole range of educational, outreach, direct project assistance types of activities in our region, which is California, Nevada, and Hawaii, that is the Pacific Region. There is our website where you can download our reports, fax sheets, case studies. We have done an action plan for each of the three states. Here is a quick map showing the eight application centers, you can see all 50 states in the U.S. are now covered with these application centers. The update, and while I think this is important and germane to the topic today, both the talks this morning suggested -- and Ken, I think, made a very good point at the end, that there is a real need for additional information and other measures to reduce perceived risks of CHP by potential adopters, and that is what the RACs are really set out to do, and we are very excited because our funding has been very up and down over the past four or five years with the vagaries of DOE budgets and so forth. The Fiscal Year 2008, we essentially got no money. And we just were given the opportunity to propose and receive the award for a three-year award directly from the Department of Energy for $1.5 million to continue the operation of the center. We are actually in negotiations with them now to make this a four-year award for $2 million, so even better. It is a 20 percent cost matched, so it is 80 percent federal funding, leveraged by 20 percent State funding, and that cost matched funding is coming from the Energy Commission, the Energy Biosciences Institute at U.C. Berkeley, which I work with, which tells a lot of interesting combined heat and power associated with bio-refineries, and also University of California cost match. I think we are also getting some cost match from SEMPRA, as well, I should have put that in; I think I did at one point.

Now, these RACs with the new funding are no longer going to be called the Combined Heat and Power RACs, they are going to be called Clean Energy Application Centers, so ours will be the Pacific Region Clean Energy Application Center, not a whole lot of change in focus, it still has a strong combined heat and power focus, but they have asked us to broaden our activities slightly to include other waste heat to power types of applications, and waste and biogas types of applications, which we have really only dabbled in so far, but which we think are very interesting. And it is possible that, in the future, with additional funding and even broader mandate, we will get into renewables and other clean fuels, and so forth to the center. So the main focus is education outreach, try to connect potential end users of CHP with the information needed to give decisions about whether it is right for them.

The new center phase -- these are just the kind of bulleted activities -- we will keep our website going, of course, and expand it, and I welcome you to visit that. We will keep doing target market workshops aimed at specific sectors, and groups of sectors. We are going to keep doing our waste heat to energy workshops which we have done in a few different regions, we will continue to update and revise our Baseline Assessment and Action Plan Reports, project case study profiles that we do, and I have a few of those today that I could hand off to you, Commissioners, to see what they look like. Another thing we are going to get more into is policy road mapping with stakeholder groups, try to figure out how we get to some of these 2020 goals and work with all of you on that. And then we also do direct project assistance where we can go into actual facilities and do audits and see if CHP is right for those facilities. So that is it. I think that is all of our time. I just wanted to give you a quick update on that and we look forward to working with you. Michael and I were remiss by not thanking Guido Franco for supporting the study that you heard about. Thank you.

MS. KELLY: Commissioner Byron, any questions?

COMMISSIONER BYRON: One, I think. But, first of all, I hope you are able to spend a little bit of that money on marketing and advertising so that more end-use customers will be aware of the services that are available to them. I forget about the formally called PRAC myself, and I think it is a really valuable asset to have. A quick question for Mr. Stadler, if I may. This is a very intriguing analysis because it includes a lot more variables, if you will, into the DG CHP modeling than we have considered elsewhere. But I take you back to Slide 15 where you had a capacity factor, I believe you said, of about 68 percent, which was very favorable. But I am reminded that a lot of times, customers, when they size any CHP facilities, it is oftentimes based on their thermal load requirements. And the problem is, what do you do with the excess electrons, and a much higher capacity factor would have substantially different results here, wouldn't it?

MR. STADLER: Well, the thing is that we are minimizing costs here, so we are putting together all the costs which we are waiting for -- by natural gas, for example, for boilers, and for electricity, and that is really a strategy implied which says, "Well, your heat is more electricity driven," so it just minimizes the cost, and that is how it looks. And the other thing is just the tariff because the electric tariff is so important to avoid all these on-peak demand charges, this means most of the time we are trying to reduce the costs based on these time of use tariffs, or demand charges, and in this sense it is more electric driven, as you have seen here.

COMMISSIONER BYRON: I would like to thank you both very much. Again, I am trying to keep this on schedule. There is a comment period that we have scheduled, and I hope that you will be here and we will take some comments from the public at this time. I note that your agenda, Ms. Kelly, does not include a break. Could we take a 10-minute break?

MS. KELLY: Sure.

COMMISSIONER BYRON: Let's try that. We will start promptly at 11:15. Thank you.

[Off the record at 11:07 a.m.]

[Back on the record at 11:16 a.m.]

MS. KELLY: So getting back on track, our next speaker is Evelyn Kahl and she is with WSPA, and early this morning I think we clearly understand that the forecast for large and small are going to be influenced by a range of different factors, and so one of the things we wanted to do with the rest of this workshop is, after we have the modelers and the people who do that type of analysis, we wanted to hear from real customers and people who are dealing with the issues in both the large and the small sector. So Evelyn agreed to come and speak with us today and talk about a lot of these large CHP facilities and what some of their issues are, and some of the things that they need to get accomplished in the future to assure that they are going to be building more CHP in California.

COMMISSIONER BYRON: Welcome, Ms. Kahl. Do we have it correct on the agenda, that you are here representing Western States Petroleum Association?

MS. KAHL: Yes.

COMMISSIONER BYRON: Thank you.

MS. KAHL: Thank you. And thank you for including me today in the workshop. I have to say, in preparing for today, I felt a little like Bill Murray in *Groundhog Day*, reliving the same experience over and over and over again. And I know that you have heard some of these things from me and other industry representatives, and we have been talking about some of these same issues for the last decade or so, so bear with me as I get through it.

COMMISSIONER BYRON: Of course. We all know that that movie does have a happy ending.

MS. KAHL: Well, that is what I was going to say, with all the creativity in this room, I hope that I come back next time and we talk about how successful the program has been.

COMMISSIONER BYRON: And Mr. Murray was reformed.

MS. KAHL: Okay, thank you. I will sleep on that. All right, I have a variety of topics on my list today, but I am really going to try to center my comments on the oil and gas industry and CHP within that industry and its potential, and the barriers to development of more capacity. The starting point here for everyone today seems to be the AB 32 goals, I will not spend time on that. We know ARB included CHP in its Scoping Plan. But I think one point that bears emphasizing and Ken spoke to it earlier this morning, is that we also have to remember we need to retain existing efficiency CHP. The Scoping Plan did not really speak to that point, but it is critical because, if we lose efficiency CHP, we really need to increase our target for more.

Another point I will touch on briefly here is, we have to remember that CHP is more than greenhouse gas reductions. I think there is a temptation both with renewables right now, and with CHP, to get stuck on greenhouse gas. It is the fashionable topic. But we do need to remember that there are customer benefits and, in an economy like this, those are really important -- cost control, on-site reliability, and business certainty. And there are also societal benefits beyond GHG, including Grid reliability, a very important component, the avoidance of transmission investment, which is required right now for renewables, and reduced transmission and energy losses. This agency, the CPUC and ARB, are all over CHP. The CEC has been a strong supporter for years, and I will not read you these quotes, but needless to say, we all understand the agencies understand that CHP is good. And the response of industry over the years has also recognized that CHP is a good and beneficial thing.

I took this pie chart from Ken's presentation earlier and marked it up a little bit. What you will see here is the oil and gas industry share of CHP refining the 1202 and EOR at 2846. The oil and gas industry has roughly 44 percent of the CHP capacity in California, so it is a very material portion of the CHP fleet. I do have to say that these numbers do not necessarily square with numbers we have, and I know there are multiple databases, but I think the fact holds that it is a large part of the CHP fleet.

There are really two typical configurations that we have in the oil fields or the refining business, one is kind of a hovering as available CHP, which you see on your left. In that situation, it is largely used to serve on-site electrical, but when thermal demand varies, there is some small export amount going to the Grid, and it typically goes as "as available" power. On your right, you see a large export CHP facility, some refineries have these, and the EOR fields do, where you have, again, a large portion of on-site use, an even larger portion of firm sales to the Grid, and often some residual "as available" sales going to the utilities, as well. So those are the two most typical situations that we see in the industry.

Statistics are hard. We have tried to get focused on these, I think you have seen other numbers from us in March, but our best estimate of oil and gas industry CHP facilities is 2,800 to 3,000, that is about a thousand lower than the ICF slide; I do not know where the differences are, but this is our best estimate. And all of this, almost all of it, was built in response to PURPA, with a few plants built in response to the energy crisis in 2001. Roughly half of the electricity that is coming from these units is exported to the Grid, and they are very efficient units. Typically, you see efficiencies on a total basis between 60 and 80 percent HHV. I think EIA reports an average of 69 percent. We tried to do some calculations on what we are getting today in California from this fleet. It was based on the EIA data, not actual data, so we used a smaller number, which is 2589. But if you look at it against a vintaged Grid benchmark over the years, we calculated savings of 4.54 million metric tons annually. And if you were to bench it against a current vintaged CCGT, you get something more like 2.94 million metric tons. So the point here is, there are substantial savings today coming from the oil and gas industry in the form of existing CHP.

There is also a lot of potential out there and our number is not developed technically, perhaps, like Ken's was, it is more practically developed, going to numbers, talking about potential, and what we came up with within the WSPA membership was about 1,722 Megawatts, broken down, most of it, in EOR, a little over a thousand Megawatts, and a little over 600 in refining. And it varies materially by facility, obviously. There are some that are already pretty well built out and some that are not. It also depends on what load projects they have planned over time, is the refinery adding load for processing units? What are oil prices? And will the oil field search for more development opportunities? And will more steam be needed? So there are a lot of different economic factors that go into what the actual potential is and could be out in the oil and gas world. But our calculation is that the 1,722 Megawatts, if they were realized, would produce roughly 1.7 to 2 million metric tons of carbon savings by 2020, which is on top of the existing. About the assumptions that we used in calculating that below, but I think what concerns me a little bit is, if you look at the ICF values, our numbers represent roughly half of the Megawatts that they have in their forecast for 2020, and about two-thirds of the estimated carbon savings based on the ICF numbers. So I suspect that we all need to sit down and look at assumptions and work through some other scenarios before you finalize the IEPR because we have some inconsistent results, I guess. But the point here is that we do have more potential, the potential is significant, and the savings would be significant.

So the Commissions all realize it is good, industry realizes it is good, so why are we here? And we are here because, despite the fact that everyone knows CHP is a good thing, development is stalled. The graph that you have before you shows CHP capacity additions from 1970 to 2006, so these are annual additions, they are not cumulative. And the purple line, the red line, whatever color that is, represents the CHP additions, and the dotted line represents the total system capacity additions. And what you see is the big bump in the middle, it is what Ken spoke about earlier, happened in response to PURPA. There were strong strong incentives and there was a lot of CHP built. And as you see over time, the development triples out and, starting in about 1996, it pretty much flattens out, with the exception of a few projects that were built in response to the energy crisis. So I think it goes without saying that we are in a state right now where there is no promotion with California policy of new CHP.

And what are the barriers that are contributing to that problem? There are a variety of them, but I have identified five here that I would like to talk about, and the first one is obvious, Ken identified it, everyone knows that it is there, there are limited export opportunities for excess power. PURPA has not been enforced for years, since basically 1996 in California. It has been undermined by the Federal EPAct to 2005. The state has not put together any state-based CHP policy to replace PURPA, and there are no real market alternatives to utility purchases for CHP products. Essentially, in California if you are building in Edison's territory, who are you going to sell it to? Primarily, your customer would be Edison. There are very few other alternatives and there are no carrots or sticks to encourage the utility to take that power. And if I am a utility, I am better off building a plant; my shareholders get a return. So I am probably going to be more oriented toward that alternative than taking CHP power.

A second area is that greenhouse gas costs right now are unknown, and so is cost recovery. There is no certainty that, if I build a plant and export my power, I can recover my greenhouse gas costs associated with compliance. And I will flip to the next slide here. This is just a schematic that shows the problem for someone analyzing a CHP plant on-site, and it is from ICF. And kind of ignore the numbers here to some extent, but on the left you see that, under a traditional system, separate heat and power, the load, the thermal and the electric load, are being served by a power plant from the Grid and a boiler that is on-site. So at that point, the host responsibility for carbon is really only for the boiler, or for the 13,000 tons here on the left. If the host puts in a CHP system, suddenly all of the emissions associated with the electricity and the steam it uses become their direct responsibility, so the CHP plant in this example now has 23,000 tons of responsibility a year. So there is increased direct compliance responsibility for greenhouse gas when you go from a separate heat and power scenario to a combined heat and power scenario.

The next barrier is utility to party load fees, the exit fees that we have been struggling with since the mid-'90s. Right now, they average from $9.00 a Megawatt hour up to $21.00 a Megawatt hour. So not only do you have to recover your capital and operating costs, you have to -- you need to be able to deal with the departing load costs that go on top of it, so it really just increases the cost of your project by this amount. And you will see two slides ahead, I have given you a table of those charges, I will not go through it now. But just looking at it gives you a sense of how complicated it is, how many different types of charges they are, how the exemptions are all over the map, it is just a very complicated situation right now.

There is complex Grid interconnection and interface rules. If you are only wanting to export a very small amount of electricity, you have a very big job in interfacing with the ISO. And so that is marginally a barrier at this point.

Then, finally, a very important one, especially in the South Coast today, are Air Quality Management District restrictions and the availability of credits. So those are the five big barriers that we face right now in developing large projects.

The Utilities have also identified another problem that they have with CHP. Not only do we have barriers, but they have concerns. And it comes from the interface of combined heat and power and renewable policy. With large projects like ours, it is important that the utility can accommodate electricity 24/7. Our refinery runs 24/7, some oil fields do, so it is important that we can have a place to put excess power when we are operating to meet the thermal demand. But the utility's ability to accommodate that power 24/7 is challenged during off-peak periods. I think we are all aware of that. There are often more must-run facilities than there is load, and it can result in an over-generation condition. Your own staff has noted in the June 2009 Report that more study is required of the over-generation problem. The ISO is apparently doing some study of the over-generation problem. And so I think we do not really have enough facts here at this point to evaluate it, and I do hope that we move forward to really evaluate this argument and problem to see how real it is.

One thing I noted in Ken's presentation earlier is I think most of the Megawatts that he has indicated would be added would not be 24/7. There is a lot of air-conditioning and other things that would not contribute to an off-peak over-generation situation. So it really does require more extensive analysis at this point.

The next graph you see is just a bar graph that tries to illustrate the problem. These are really only illustrative data, they are taken from some 2007 ISO Reports, but what you see on the left depicts the bar of minimum generation in 2010, those are the must-run facilities in 2010, assuming that you have a 20 percent RPS requirement. And what the bubble says above it is, in 20 percent conditions by 2010, on average you are in balance between your minimum load and your minimum generation. That does not mean you will be out of balance during certain hours of the year, and I think the utilities would tell you that they are even out of balance today sometimes, but on balance it does not look too bad under a 20 percent RPS. If you get to 33 percent RPS, which is the bar on the right, we see that the minimum generation stack grows, and it grows because you have added more wind with the renewable policy. And we have layered on top there the bright pink box on top, which is the new CHP goal of 4,000 Megawatts. So if you were to assume all of that were 24/7, you can see that the total minimum generation stack is above the red line, which is the minimum load stack, or line, meaning that we have got over-generation under a 33 percent RPS scenario. So, again, this is something we know very little about, particularly we do not because we do not have the data, but it does require study before we make any decisions for closing CHP.

So we have got barriers that are faced by industry, we have the Utilities concerned about interface with the RPS, and we have a variety of other oppositions to state CHP policy that you listen to, that the PUC listens to, and that we really need to address. The first one is, well, the CHP can just sell directly into the market, you do not need a CHP policy program. And, again, as I discussed earlier, there really are no real market alternatives today, the utility remains the primary retail seller in California and that is the primary purchaser. And the MRTU is not developed yet at this point enough to support any new projects, let alone a new CHP project. Another argument is that the Utilities do not need the power with CHP characteristics, and I think this ignores the full range of CHP benefits, it places the whole burden of the over-generation problem on CHP policy, and it does not look for the solutions, like addressing things through time of delivery, trying to analyze really how much of it will be an over-generation problem and how much will not.

CHP is not as efficient as separate production alternatives, some have made that argument. And it is true in some cases. I think there are some existing plants now that are not that efficient, but it is not true in all cases and, going forward, we have the opportunity to set standards that preclude that result.

This is my personal favorite, it is cheaper to reduce greenhouse gas by planting trees in Brazil than to install CHP. And that is one we face. And obviously it ignores CHP benefits, again, the full range of benefits and co-benefits for California, and California needs to do all it can to maximize the AB 32 goal achievement.

And the final one, and this is one that has come up at the Federal level as they have been debating Waxman-Markey, the argument that CHP has matured and it does not require policy support anymore. This is old news. This is 1970s PURPA, and we no longer need this policy. You have all figured it out. And I think this misses the point that maturity is not the issue here, it is the characteristics of the generation that require policy. This is a type of benefit that spans both the electric and the industrial sector, so you cannot look at it singularly in the electricity sector. It has to follow thermal load, which sets it apart from other types of generation. And third party CHP development is double trouble to the utilities. As I said earlier, not only does it compete with shareholder return projects, but it takes load off their system, so it is really not that attractive to a utility, which we recognize.

So those are the problems that we face in getting through to a new CHP policy in California. And, as I said earlier, there is a lot of creativity in this room and I trust we will get through those.

I will turn briefly here to cut to the chase on Slide 19 with the ICF analysis. I want to just start out by emphasizing some important points that ICF made. The first is that, under current policy, CHP will fall short of ARB goals. We know that. We are all here today, hopefully, to get beyond that, but it is critical to keep that in mind. And ICF noted that we need aggressive CHP stimulation. As Ken said, PURPA was aggressive, perhaps too aggressive, but we cannot be shy in developing a policy that will really stimulate this market. And the third important point is that the greatest market and GHG benefit comes from preserving existing like the oil and gas CHP, and pursuing the remaining large CHP technical potential.

Again, I think the ICF report is obviously a product of assumptions and I bet there are as many assumptions as there are people in this room today. And my hope is that we can get together over the next few weeks an run a few additional scenarios to see how sensitive the model is to varying assumptions. And I have put down a list of things that we would like to test with ICF, the heat rate used in the benchmark to calculate GHG savings, we think it is strikingly low, particularly when you look at the number for existing plants on the Grid right now; their power price forecast assumptions for the export program, again, I think those are probably lower than we would like to see used, certainly; capacity factors for new CHP, obviously that is dependent on the installation and application, but I think we would like to test some of those assumptions; efficiencies for new CHP, again, testing those and different combinations of different types of applications; and then looking at market penetration. I think when you move the power price forecast, you are probably going to see more market penetration. And we also want to look at the acceptance rates that they use with respect to the projects.

So the next steps. What do we need to do? The first step is to refine and implement the PUC policy decision that was adopted in 2007. It is now 2009 and it still has not been implemented, and I doubt that we are going to get anything new in place soon, so it would be well to keep existing plans by implementing the decision that has already been adopted. It seems like a no-brainer to me. Second, we need to analyze the over-generation potential, as I discussed earlier, and your staff is apparently headed in that direction, as is the ISO, and that would be a really positive step. And then, finally, and obviously it is simpler to say than do, but to coordinate the CEC, ARB and CPUC to develop a comprehensive and durable policy. So thank you very much for your time today.

MS. BROWN: I have a quick question for you. Is your industry advocating, as part of Waxman-Markey, a structure under a cap in trade or a cap in dividend program that would stimulate CHP development that you described?

MS. KAHL: Uh, no. As I understand it, my last read of Waxman-Markey is it really does not do anything for oil industry CHP. There are provisions in there for CHP, but they are qualified such that they do not really apply to these types of facilities.

MS. BROWN: But is there some that could be done --

MS. KAHL: Absolutely, yeah. I think there are a couple of things in Waxman-Markey, one is that it has a provision, again, with too many caveats that would allow recovery of greenhouse gas costs for CHP sold to the Grid. But it would not apply to these facilities. There are also provisions that would take revenues from the greenhouse gas allowances back to retail providers. And the PUC issued a decision last year that would do the same thing, it would take the revenues back to retail providers, but they included CHP in that, wisely, because essentially a CHP plant is serving retail customers, so that would also be beneficial in the Federal legislation.

MS. BROWN: So did that scheme with the benefits accrue to the customer or to the utility?

MS. KAHL: You mean the revenues?

MS. BROWN: Yes, the revenues.

MS. KAHL: Well, what happens, at least in the PUC decision, they would auction allowances. The auctioned revenues would be spread in some proportion to retail providers. That would include the CHP plant serving the customer, and I believe, Michael, the way you had it set was those revenues had to be used on behalf of the customer and, you know, possibly in further GHG reduction measures.

MS. BROWN: Thank you.

COMMISSIONER BYRON: Ms. Kahl, thank you very much. Excellent presentation and there are many things we could go into, but in the interest of time, I am going to try to reserve some time for others from the audience to comment. I will note one thing that you said, that I want to make sure we close on, that is that back in slide 9, you had much better results than the ICF study in regard to GHG savings, and I am interested in making sure we try to settle that beforehand. When I say "beforehand," before we publish the contractor's report.

MS. KAHL: Thank you.

COMMISSIONER BYRON: So thank you very much. Again, there are many things we could go into, but do not give up, okay? We are glad you are here and we appreciate your continued efforts to point out customer and societal benefits.

MS. KELLY: Okay. And, again, Commissioner Byron, that was a draft report. We were going to use this venue to get good public input, and we are going to work with people with their comments before we finalize the report.

COMMISSIONER BYRON: Good.

MS. KELLY: The next presentation, we are going to be talking about AB 1613. And getting updates on the process at the Energy Commission and the CPUC. Art Soinski, who is responsible for doing our AB 1613 Technical Criteria Guidelines, is going to, I think, give everybody good news, and update you on the schedule. Art? Give them the good news first.

MR. SOINSKI: The good news, okay. The good news is the schedule, and the expected date for the release of the draft Guidelines is today, but they were actually posted on our website yesterday, so they are there for your perusal and comment over the next couple of weeks. The comments are due on August 6th on the Draft Guidelines, and then there are also reporting forms posted, and I guess the question will become there are guidelines and then there are reporting forms, what are these reporting forms? Legal counsel and I have been going back and forth since April 13th when I first presented my draft proposals for what the technical metrics would be for the guidelines, and it has taken a long time going back and forth deciding how to structure them to make them easy to use and understandable. And the reporting forms were originally going to be part of the Guidelines, but they are now -- well, they will be, but they will be really separately. They have a lot of similarity to what was done in the self-generation incentive program as far as the format of the type of information that is required. In addition to that, the forms will require attachments of basically diagrams of the CHP system and the thermal host facility, to track exactly how the energy is used, especially the thermal energy. At the April 13th workshop, there were comments about the fact that what is really -- one of the real deficiencies in the SGIP program is the explanation of what has to be done for accounting for the thermal energy, which is the difficult part. The electrical part is obviously very easy, but the thermal becomes much more difficult. So with the comments due on these two sets of Guidelines and Forms, on August 6th and 17th, on September 1st, we will put staff recommended Guidelines and the Forms will be finalized and posted. There will be an Electricity and Natural Gas Committee Workshop on September 22nd, and then the original schedule for November 18th for the adoption of the Guidelines and the Forms.

I am not going to talk about the details of the Guidelines. If you want to see what our thinking was, you can go back to the April 13th presentations and transcripts to find out. I just want to highlight what the changes are, what I consider to be the most significant changes. One is that, previously, we did not talk about a difference between topping cycles and bottoming cycles, and both the stakeholders and now the Public Utilities Commission have come in and recognize that there is a difference between the efficiencies, ways that are considered for topping cycles and bottoming cycles, and those are incorporated. In essence, if a bottoming cycle does not use supplemental firing, then there is no efficiency requirement imposed under the AB 1613 Guidelines. Definition of useful has changed from "made available for use" to "used in a productive and beneficial manner," which is a requirement that is actually in FERC regulations. The Greenhouse Gas Emission Environmental Performance Standard, which is 1,100 pounds per Megawatt hour in the legislation; and I guess, as a response to SB 1368, for AB 1316 it is 985 pounds per Megawatt hour. And this reflects an issue that has been brought up both in the ICF presentation and in Evie Kahl's presentation, is that what is the metric that you are comparing your CHP system to. That is a very important standard to understand, and certainly we would appreciate comments on that within the context of both this workshop and the posting of the Draft Guidelines.

There is an issue of who is going to really look at what the characteristics are, what the design is, of the CHP system, and we will make a judgment as to whether it complies with the technical requirements given in the Guidelines. And what we have now in the draft is that the Energy Commission's Executive Director will issue something called a Certificate of Initial Compliance, which will determine whether or not all of the requirements have been met, based on design and analyses submitted by the Applicant or the Owner/Operator of the CHP system. And after that, there will be annual monitoring and reporting, which will be done on forms very similar that are used for the initial compliance, except, instead of having forecast data, they will have actual performance data.

And that is really the summation of the status of the Guidelines.

COMMISSIONER BYRON: Mr. Soinski, I think I would correct you in one regard and that was that comment about how stakeholders, and I believe you said agencies are, you know, kind of becoming aware of the difference between the topping and bottoming cycles. The correction I would offer is that a lot of stakeholders were well aware of that long before we paid attention to it.

MR. SOINSKI: Yes, I have been beaten over the head by a certain stakeholder, whose name I will not mention.

COMMISSIONER BYRON: Well, I might.

MR. SOINSKI: But she is right.

MS. KELLY: Any questions?

MR. SOINSKI: Or, at least, I agree.

COMMISSIONER BYRON: Well, you condensed a lot of material in a short presentation, and I certainly recommend folks to look at the Guidelines. We are very interested in their comments and there are some new changes that I think are favorable, but others may not. So we are certainly interested in your comments. Thank you, Mr. Soinski.

MS. KELLY: Our final presentation for the morning is Michael Colvin from the CPUC. We have been working very closely with the CPUC, and I think we are both on track to take care of our responsibilities under AB 1613 and meet our January 2010 deadline. And Michael is going to update us on those activities.

COMMISSIONER BYRON: Mr. Colvin, I am glad you are here. It is great to have someone from the Public Utilities Commission, and your presentation looks like it is going to cover the gambit of so many issues that are going on at the PUC. Are you tracking all of these proceedings and issues at the PUC?

MR. COLVIN: Yeah, pretty much. Everything goes through my desk.

COMMISSIONER BYRON: Good, then I hope you will be here because I suspect there may be some more questions for you.

MR. COLVIN: I look forward to them.

COMMISSIONER BYRON: Good.

MR. COLVIN: I wanted to say, just first of all, thank you very much for having me this morning, Commissioner Byron and Laurie, it is great to see you again, and I guess Susan has stepped out, but I am thrilled to have someone from Commissioner Boyd's office, as well.

I wanted to just very quickly kind of do a CHP policy update, that there are a lot of moving parts, as Commissioner Byron alluded to, and hopefully we can try and shed some light on what is going on, what are kind of the current updates on at least some of these moving parts.

This is a slide that I kind of trot around on a lot, but I think that it is really important to remember that combined heat and power, at least right now, exist on many different places at a policy level both in the State of California and specifically within the CPUC, we have a lot of different dockets, we have a lot of different ways to kind of talking about combined heat and power. And it is done based on different size thresholds, different efficiencies, different technologies, and each of these kind of create a different policy home, and so it makes it a little difficult to try and track and figure out what is going on with CHP as a whole. And I think one of the big things that has come out of the last year or so is a real acknowledgement that we need to not only do an update to CHP policy, but we really do need to try and have the coordinated and a centralized policy update. But these things cannot be done in separate parts anymore. So a lot of the things that you hear me talk about today, I am really going to try and see if I can connect the dots for everyone.

Probably, as referenced in the ICF Study this morning, probably the most visible form of combined heat and power is done through the Qualifying Facility Program. The Qualifying Facility is established under PURPA. As alluded to by Ms. Kahl earlier, the most recent decision coming out of the PUC from the 2004 docket was in September 2007, and it really tried to stake out information for CHP based on Furman as available, whether you are existing or new, and whether you are kind of small or large. Coming out of that decision, a standard offer contract for large QFs has been proposed by the Commission. It is on hold, and I will explain that in a second. Something else coming out of that decision is how essentially facilities get paid based on what we call the "Myth." The Myth is not a myth anymore, it is a actually out there. That was the plan where it is mythed -- okay, bad joke. So the market index formula was adopted by the Commission in 2009. All QF issues, all Qualifying Facility issues, are currently being held in abeyance pending settlement discussions amongst the parties, and hence why I said the standard offer contract has been proposed, but not adopted yet, it is being held in abeyance pending the resolution of those discussions.

Switching tracks, going from one program into another, we have the Self-Generation Incentive Program, as created by 2778. It provides an upfront incentive for up to one Megawatt of a facility and it allows for siting up to 3 Megawatts, so it would be kind of a 3 Megawatt facility, you get paid up front in some payment for that first Megawatt. Currently, fuel cells that do combined heat and power, are all fuel cells, are eligible under SGIP because they catalyze natural gas. Other CHP technologies that once were eligible under SGIP have been taken out because they combust natural gas. It is worth noting that there is proposed legislation to modify SGIP to essentially undo that change, and to put back those technologies and also to include storage. As everyone knows, legislation is changing very very quickly right now, so we are all kind of looking at it very closely and figuring out what is happening behind the scenes. The way that the SGIP program currently works is that there is a different incentive level for all technologies and I am specifying fuel cells here because that is a CHP technology, but it is very different incentive levels based on fuel type, whether it is a renewable or non-renewable fuel. Some more information, I like giving websites or docket numbers whenever I can, so if you need more info on the SGIP program, it is there.

Combined heat and power -- shifting gears again -- combined heat and power, when we talk about AB 32, it plays two different roles, and it is kind of an interesting dynamic that is worth remembering. CHP is an emitter of greenhouse gasses, when you have primarily the fuel use is natural gas, natural gas combusted emits greenhouse gasses. But, CHP is also an emissions reduction strategy, or complimentary measure. We kind of use different terms, depending on the context. But combined heat and power is a way of reducing greenhouse gasses, compared to something. And any policy update that we do, whether the recommendations in the IEPR, through the PUC's efforts, anywhere that we do it, we need to recognize both of these facts, that is both an emitter and an emissions reduction strategy.

The two Commissions, both the PUC and the Energy Commission together, gave the Air Resources Board a series of recommendations on CHP and a whole variety of other things back in October of 2008, I list a Decision number. In this call reference, some of the decision of what happened with [inaudible] with allowances a few moments ago. I wish Ms. Brown were still in the room. There seem to be some additional questions. But since this was both a CPUC and an Energy Commission decision -- I should say series of recommendations -- to the Air Board, there are additional clarifications and we can certainly provide a briefing or an update on that, so I note that for both your office and for Commissioner Boyd's office.

Shifting gears slightly, when we talk about how do we reach the Scoping Plan target, what is it that we are really going after? Well, the Scoping Plan states that we want 4,000 Megawatts of new combined heat and power to get to our 6.7 million metric tons. In pushing on that a little bit, do we want 4,000 Megawatts? Or do we want 6.7 million metric tons? And I think the answer really is we want the million metric tons productions. And so, at least from the PUC's perspective, is that our approach is to figure out how can we approve the efficiency of the existing fleet and make certain we are retaining the efficient parts of the existing fleet, and bring on new highly efficient facilities in order to reach our emissions reduction targets, that we really think we need to look at all three of those in order to be able to reach the proportionate share of the 6.7. So that is certainly, at least, kind of our bigger strategy. Now, when I talk about this, what is this policy framework for CHP, when I talk about what is the meaning of it, for it to be coordinated, I have shown the next two slides a bit, but it is again just kind of worth mentioning. I have said a lot of this already, but we know that there is some existing barriers for CHP. The feed-in tariff for 1613, which I am going to talk about, I have not forgotten about it, I promise, but this feed-in tariff will be a part of the framework, but it is not the only part of this framework. As I have sort of hinted at, when we want to try and talk about coordinating and centralities in policy, there will be a new rulemaking from the Commission, we have promised it back in October '08 to try and coordinate these policy issues. And the new rulemaking, it is partially to accomplish the greenhouse gas reduction target from the Scoping Plan, but also to really make certain we are ensuring all the other policy drivers of why we like combined heat and power in the state. And I think this morning we have heard a lot of those other ones, so I will not go into those details again, in the interest of time.

The timeframe is to do the framework development in the second half of 2009, and into 2010, and implementing it during 2010. And again, how these pieces sort of fit together, we have small, we have large, we have new, we have existing. AB 1613, the feed-in tariff really goes after small new selectory powered combined heat and power, and we really need to make certain that we are looking at these kind of other three boxes, and the intention is that we do a

1613, we really need to coordinate with the rest of the pieces.

So I wanted to give -- and I apologize, this is happening automatically on me -- some details on 1613. So what is eligible for this feed-in tariff? The CHP facility nameplate can be up to 20 Megawatts, and that has to be new or re-powered. The goal is to maximize the use of waste heat by promoting a thermal match. The GHG reductions from these facilities will obviously count towards the Scoping Plan target. And I think the real idea of having AB 1613 is to allow, once you create a thermal match, is to allow the excess electricity to be delivered onto the Grid. There are currently two contracts that are under development at the PUC for 1613, one for what I would dub small facilities. We are trying to figure out right now, you know, what is the cut-off for small? Is it 1 Megawatt? Is it 5 Megawatts? What is that? And then one for kind of the medium-sized facilities, less than 20, but kind of, you know, is it going down to 1? Going down to 5? And, again, for those of you who are interested in participating in our process, our rulemaking number is there at the bottom and I encourage you to either talk to me afterwards, or to participate via the rulemaking process.

Just to give you an update on the schedule of what has happened and what will be happening, the staff proposed kind of a first proposal and did a workshop at the end of February. Coming out of that, we got a lot of really great feedback, a lot of really good information, and one of the things that we really heard is that the contract is too complicated, it is too dense, we need to get a way to figure this out, that these are not, you know, 100 Megawatt facilities, these are relatively small. We need to figure out how to streamline this. And we put it back to the parties to say, "Let's try and streamline this." So some additional negotiations happened on the contract in the spring. At the same time, we were able to coordinate with the Energy Commission on some of the technical guidelines on some of the efficiency matters, and I believe that they now -- so they are posted as of today. I got an e-mail at 5:00 a.m. So I was excited to see that they are officially out.

There will be a final Commission staff proposal to be issued probably either late next week or the first week of August, so I am saying August of 2009 so I do not lie to you. There will be, as a part of that proposal, two new proposals on pricing, and I think one of the things that we heard from the LBL folks this morning is pricing is really a key driver into figuring out how this tariff works, and we have two different proposals that we recognize that the record was a little thin on pricing at the moment, and we really wanted to try and develop that as much as we could.

There are some additional proposals on both the contracts coming out of the negotiations and on just overall program operations for their rate of program cap, how does that interact with SGIP, etc. etc. We anticipate that there will be a proposed decision by the late fall and we are certainly on track to having a final decision done by the end of the calendar year. One thing of note is that, as a second phase, once the program is up and running, there was a requirement with law to try and develop what we call a pay as you save pilot program, and we really wanted to see what the final tariff looked like and what the final contract looked like before we developed that program, so it is a phase 2 issue, and my guess is we will not get to that by the end of the calendar year.

So that is just kind of some brief updates on certain -- there are probably a lot more questions, but I would like to yield a lot more of the question time to the ICS Study because I know that is what everyone really came to hear about today. So I thank you all very much for your time.

COMMISSIONER BYRON: Thank you, Mr. Colvin. A couple of quick questions, please. Back on Slide 6, when you talk about the joint decision that we had, or the joint recommendation, as we prefer to call it, to ARB, you said something that struck me as interesting. Did the PUC provide an update to that joint recommendation? Is that what you said?

MR. COLVIN: No, but what I think I was trying to allude to, and unfortunately she is out of the room, but I think Ms. Brown was asking Ms. Kahl some questions about those series of recommendations and what it is that we had said, and so I was just trying to say, if anyone needed a reminder or an update, I would be more than happy to get that refresher on certain Energy Commission stuff, but I would also be happy to do it for you, as well. But --

COMMISSIONER BYRON: I do not think I need it.

MR. COLVIN: Okay, fantastic.

COMMISSIONER BYRON: The -- seen it was a joint decision.

MR. COLVIN: I am just saying from some of the questions I heard, there seemed to be a little confusion in some of the questions Ms. Kahl got, so I was just trying to be proactive.

COMMISSIONER BYRON: All right, good. There was a term you used, and I am not familiar with it, in terms of PUC parlance, but you emphasized it, and that was that we are going to hold this -- this was in regards to the large contracts, the large CHP contracts -- we are going to -- they are being held in abeyance.

MR. COLVIN: Yes.

COMMISSIONER BYRON: So does that mean that they are continuing to generate and no one is getting paid? Or does that mean we just keep the existing contract until we have a new one?

MR. COLVIN: It is not that -- the existing contracts are still being honored.

COMMISSIONER BYRON: Okay.

MR. COLVIN: Yes.

COMMISSIONER BYRON: And although I do not really -- we do not have the time and this is not the venue, although you, I am sure, you may well get some comments with regard to the proceeding on AB 1613 that is going on, do you think that we are going to come up with a single tariff? Or do you think investor-owned utilities will be permitted to go their own way? In other words, will we have three different tariffs?

MR. COLVIN: I am hoping that we will have two, one for small facilities, as I dubbed it, and one for medium-sized facilities. But there will be a size not --

COMMISSIONER BYRON: Size spaced.

MR. COLVIN: But certainly the path that the Commission has been pursuing is to have one for each of the utilities, and then we divide it up based on size.

COMMISSIONER BYRON: Okay. And given the complexity of the way that we have proceeded with implementing AB 1613, you know, dividing it up into phases and parts, and the complexity that we have put around this, do you think we are paying enough attention, or paying any attention, to the importance of some regulatory certainty around this issue? Customers need regulatory certainty. Do you think we are paying enough attention to that?

MR. COLVIN: I think, as best as we can given the fact that we are trying to develop the rules to other programs, as we speak, that I think regulatory certainty will be provided once we have the rules established.

COMMISSIONER BYRON: I think we, as agencies, we forget about this, that this is an extremely important and maybe others will emphasize it. This process takes a long time, and during that time, we see the difficulties that the companies have putting together their financials and making a case in their respective companies for making this work. I think this often is forgotten and that is why I just wanted to bring it up. Mr. Colvin, thank you for being here. I will release you in terms of my questions, but I want to make sure we have got -- I think we have about a half an hour. Is that correct?

MS. KELLY: Yes. We certainly do. We are a little bit behind, but that --

COMMISSIONER BYRON: Oh, we are. We are a little bit behind. We are way behind. I would like to afford some opportunity for public comments, so let's ask those that wish to comment at this time if they could be brief and if they have any questions for the earlier presenters, and we will see how quickly we can do a morning comment period.

MS. KELLY: Thank you, Michael. And just to remind everybody, just come up to the podium, we are not using blue cards, please state your name and give your card to the Court Reporter. Anybody? Nobody?

COMMISSIONER BYRON: Maybe everyone is hungry. Ms. Vaughan.

MS. VAUGHAN: Hello, Commissioner. Thanks, yeah, I cannot let the opportunity go by.

COMMISSIONER BYRON: Please.

MS. VAUGHAN: My name is Beth Vaughan, I am the Executive Director of the California Co-Generation Council, and the CCC is an association of companies that operate 32 gas-fired co-generation projects, which collectively produce approximately 300 Megawatts of electricity. As qualifying facilities, these projects provide power to California's three major investor-owned utilities. Our member CHP projects supply energy -- well, basically, when you look at Ken's pie chart, we are in every aspect of the pie chart. We have a range of thermal hosts, including universities, prisons, paper manufacturers, food processors, airline facilities, U.S. Naval operations, and hence all recoveries in petroleum refineries. And on behalf of the CCC this morning, I would like to express our support for the WSPA presentation on large CHP given this morning by Ms. Kahl. While her focus is on the oil and gas industry CHP facilities, her comments equally apply to the large institutions and industrial CHP interests that we represent. On Slide 9 of Ms. Kahl's presentation, she identified more than 1,700 Megawatts of new CHP that WSPA members could install with the support of State CHP Program. The CCC also has members with growing thermal requirements in energy intensive industries, whose managers are familiar with CHP, and thus are more likely to pursue CHP at longer paybacks if the state gets its policy house in order. The potential Megawatts of new large CHP identified by our two organizations, alone, contrast with the large CHP market potential identified by ICF in their presentation this morning. As Slide 18 of the WSPA presentation indicates, this number has changed considerably from the ICF May 2009 update, and from the CEC's prior CHP market assessment of April 2005, suggesting that ICF's assumptions have changed dramatically, and we did hear from Ken Darrow this morning about those assumptions, and when we initially looked at the slides, we were puzzled to find that the dramatic reduction, just 880 Megawatts by 2020, even under the most favorable scenario, with all the pro-CHP policies in place, and this compared drastically to the 2,800 to 4,300 Megawatts of export CHP they had in the prior two studies. So we would like the opportunity to discuss with ICF their new assumptions and their reasons for them. If the state were to address the barriers to CHP identified both in the WSPA presentation and the ICF presentation, the CCC suggests that a more realistic market penetration curve is the stronger prospects curve which you find back in the 2005 study, Figure 3 of the Executive Summary in the 2005 CHP Market Study. Our overall observation is that the choice of a few key assumptions such as the shape of the market penetration curve and the export price can significantly change the results. It would be of considerable value if the sensitivity of ICF's results to these key factors could be identified clearly in the final report. And I make the same observation concerning the importance of the key few metrics also find the calculations of the expected greenhouse gas emissions savings from CHP, that both CARB and ICF have advanced. By comparing key metrics that contribute to the calculated greenhouse gas emissions savings for CHP in the CARB Scoping Plan, and in the ICF Study, it is apparent that different assumptions have been made regarding CHP capacity factors, the efficiency of new CHP projects, and the benchmark for greenhouse gas emissions if the electricity is produced from the Grid instead of from CHP. If the same assumptions are used for these metrics, and if the market potential for large CHP is significantly greater than ICF projects, as the CCC believes is true, then the difference between the CARB and ICF projections for greenhouse gas savings from CHP by 2020 can be significantly reduced, or even eliminated, compared to the factor of 2 shown in the ICF Report. Consequently, the conclusions and recommendations of any study need to be considered in context, and the input assumptions for these key metrics needs to be agreed upon by stakeholders prior to policymakers taking action. We look forward to providing ICF and the Energy Commission with more detailed comments since we have had the opportunity to review and analyze the ICF draft report in greater depth. Thank you.

COMMISSIONER BYRON: Thank you. I appreciate your comments and appreciate you being such a fast talker.

MS. VAUGHAN: There it is. I want to get to lunch, too.

COMMISSIONER BYRON: Mr. Redding.

MR. REDDING: Yes, Commissioner Byron, thank you. I want to make three quick points. The first is, I am working as a consultant with a California cement maker, and we are interested in a CHP project, as well as an on-site power plant, and renewables. And I wanted to underscore the point you made just before this question and answer period about regulatory certainty, because that is certainly staying his hand at the moment, and in particular, will be installing a bottoming cycle, which is basically making use of energies otherwise being thrown away, will result in any greenhouse gas credits. And the incentive for him is just making more product and staying in business, but it is dependent upon whether he gets credit for it, so the sooner that decision can be reached, and hopefully in favor, the sooner this investment will be made. Secondly, I wanted to offer my perspective on why there has not been the market penetration in small CHP. And this is a little different perspective than maybe you are used to. I have been involved in starting up three energy companies, I am doing my third one, and each time we have looked at doing project development for CHP, and in each case we have never decided to pursue the small CHP, because the transaction costs are really high. If a customer walks in the door with a contract and a check, there is still engineering and project development and procurement, and you can -- it takes about the same amount of cost to do 100 Megawatts as it does to do 10; but they do not walk in the door, so you have to send your sales team out into the field and a lot of them just turn up empty. And so that is certainly one reason why we have not pursued the smaller. I had a third point and I have forgotten it, but thank you for your time.

COMMISSIONER BYRON: Thank you, Mr. Redding. I noted, you know, that our regulatory process is probably much more conducive to keeping interveners in business than it is keeping California manufacturers in business.

MR. REDDING: Oh, yes. I did remember, thank you. I was -- it seemed to me that the Public Utilities Commission does not share the enthusiasm for CHP that this Commission does. I thought one of the slides -- I was reading between the lines, perhaps, where it said, "What is the real goal? CHP or Greenhouse Gas Reductions?" And the comment was made by Mr. Colvin it was greenhouse gas reductions. So I am wondering if, despite your working together, putting together joint policies, that you in fact share the same degree of support for CHP?

COMMISSIONER BYRON: I think, in fairness to PUC, they have the added responsibility of balancing the financial means and interests of investor-owned utilities in making their decisions.

MR. REDDING: Thank you, Commissioner Byron.

COMMISSIONER BYRON: Thank you.

MR. WILLIAMS: Good morning, Commissioner Byron. You probably want to hear from a utility this morning.

COMMISSIONER BYRON: Absolutely. Please identify yourself.

MR. WILLIAMS: I am Ray Williams from Pacific Gas & Electric Company, and I will keep my comments limited this morning. First, I would like to thank the CEC and ICF for their thorough analysis. And I also would like to thank Mr. Darrow for offering stakeholders the opportunity to go through his analytics and hopefully improve it, and I think we can help, at least on the utility heat rates side, some of those assumptions. So it is an open process and I really appreciate it. In terms of the ARB analysis that got to the 6.7 million metric tons of reduction, we have not had that -- we do not have that analysis, and I was surprised to hear it was based, at least in part, on high 70s co-gen efficiency. And, on average, in commercial practice in an operation, that may be difficult to achieve, so I would also like at some point to be able to compare the ICF analysis against what the ARB has done. I think that would be useful for all the parties here. While this analysis, I think, can improve expectations, just by going through it and being thorough about it, and help us all get to a good estimate, the real proof is in the procurement process, which the Public Utilities Commission is now trying to set up, both through implementation of 1613, and also for large CHP. And we look forward to engaging on both fronts. Finally, while I really do not like to respond in real time to presentations, I do want to make one point about the emissions quantity that Evelyn Kahl raised, and that is that it is quite clear that the CHP emissions -- that industrial facilities' emissions will increase with CHP, no doubt about it, they will have an electric gen rate where there was not one previously; however, if it is an efficient facility, and more efficient than what is at the margin in the market, knowing that those compliance costs will increase electric prices, they actually should be in a better position economically with the CHP facility, if it is more efficient than the market overall. So their emissions may go up, yes, their compliance costs may go up, but I would expect, as electric wholesale prices increase at a rate presumably reflecting a less efficient marginal unit, they will economically actually be in a better position. So that is just one comment that I --

COMMISSIONER BYRON: Sure. And stated another way, that is why the agencies this government are interested in CHP is because it is --

MR. WILLIAMS: Exactly.

COMMISSIONER BYRON: -- more efficient. But, of course, this is also the additional costs that get added on to CHP facilities, as well, as our last commenter and others have indicated.

MR. WILLIAMS: Agreed. Those are my comments for this morning.

COMMISSIONER BYRON: Very good.

MR. WILLIAMS: Thank you.

COMMISSIONER BYRON: Thank you, Mr. Williams. I hope you will be here for the rest of the day.

MR. WILLIAMS: I plan on it. Thank you.

COMMISSIONER BYRON: I think everybody is hungry.

MS. KELLY: Okay. What time would you like to have everybody come back?

COMMISSIONER BYRON: Well, you were kind enough to give us an hour and a half for lunch, but I am going to suggest that we try to be back here at 1:15, so that we can try and return to schedule. I apologize that we did not leave a full half hour for comment this morning, and I know that people may want to break for lunch, but I will certainly do my best to make sure we have as much public comment opportunity so we can hear from everyone that is interested in speaking. So, well, looking at the clock right now, according to that clock, let's try at 1:20.

MS. KELLY: Okay, fine. Everybody, see you back at 1:20. Thank you.

COMMISSIONER BYRON: Thank you.

[Off the record at 12:20 p.m.]

[Back on the record at 1:26 p.m.]

MS. KELLY: Okay, welcome back, everybody. This afternoon, we want to just change things just a little bit.

We wanted to start getting input from people who are out there developing CHP, publicly-owned utilities, we have somebody from Rural Electric Co-ops here today, and then, as we go on with the afternoon, just talk to people about wastewater treatment, all these different opportunities that are there for developing. So the first person is Mark Rawson. He is from SMUD, the local utility, and he is going to talk about the SMUD perspective on greenhouse gas reductions and CHP. Mark.

COMMISSIONER BYRON: Mr. Rawson, welcome back. We are glad to see you again.

MR. RAWSON: Thank you. Thank you for letting me in the building.

COMMISSIONER BYRON: Any chance you would consider staying?

MR. RAWSON: For at least the next couple hours, sure. No, thanks for giving us the chance to come talk to you today about CHP and what SMUD has been up to. Thank you, Linda, for giving us an opportunity to come and talk.

I thought what I would do in my discussion today, and I am going to be followed by another gentleman representing Public power that is going to talk to you about a specific project. I am going to take it to a little higher level discussion about, you know, why is SMUD interested in combined heat and power, and what have we been doing. I will touch on kind of where we are at in our thinking on a business model for us, incentives, what our preferences might be there, and kind of our next steps.

So SMUD has a whole host of drivers that we believe CHP is very well aligned with. We have adopted core and key strategic values that drive a lot of our decision making relative to, you know, project development, resource planning, etc. And CHP is aligned with quite a few of those, actually. It helps reduce greenhouse gas, which we have discussed this morning. An important point, I had not heard up to this point that I think the Commissioner touched on, is it gives our customers options for saving energy within their facilities. We do believe in the right types of applications that can provide system reliabilities, it certainly can help reduce peak load, which is a big issue for us, and it also is one of our strategic directives to develop and to deploy cost-effective DG. So it fits all of those nicely. Another key driver, drilling down a little bit with respect to sustainable energy, renewable energy, etc., back in December of last year, our Board revised one of our strategic directives around resource planning and developed a sustainable energy target for us as part of one of these core values. And as part of that, we defined a 2050 target for reducing greenhouse gas emissions. As a subset of the strategies that we are pursuing for that, we adopted a very aggressive energy efficiency target by 2018, and we accelerated what used to be our 20 percent by 2010, RPS goal, to a 33 percent RPS goal by 2020. And what that means for us in practical terms on this chart, it is a little busy chart, but I think the takeaway from this points out to an important discussion that was had by the morning speakers, having to do with kind of this, you know, combined heat and power and greenhouse gas emissions. But if it is done in the right way, it can be a strategy for emission reductions. So this blue line on this graph shows, you know, what our emissions would look like going out to 2050, and the scale on the bottom is a little bit distorted here, and the vertical axis is the emissions, greenhouse gas emissions. And what you can see with our new sustainable energy target, this red line, you know, to get to 10 percent of our 1990 levels by 2050, is a pretty aggressive task for us to accomplish. And specifically within this chart, the three utility scale co-gens that we currently own and operate with host customers here in SMUD service territory, and our new combined cycle power plant, Consumnes Power Plant down there on the bottom, and I think this chart illustrates kind of this conundrum that we are in with respect to the combined heat and power, and greenhouse gas emissions reductions. As we go forward and have to significantly start to reduce our emissions to meet our 2050 goals, you know, we are going to be faced with what we are going to have to do with our existing thermal assets. And those co-gen units are good assets for us, you know, they are relatively high efficiency generation sources that provide useful thermal energy for some of our key large industrial customers. But that chart kind of illustrates some of the challenges that I have shown here on this chart, is that, you know, we are going to have to get our carbon emitting sources down to 10 percent, our large hydros, you know, 15-20 percent today, so that leaves this huge wedge in that previous chart, 70-75 percent that we are going to have to meet somehow. With a doctrine of 33 percent RPS, you know, are we going to have to go more than that after 2020? Are we going to have to implement much more aggressive demand-side measures, carbon sequestration? Are there other non-carbon sources out there purchasing off-sets? All these are things that we are going to have to scrutinize as we go forward really to accomplish our long-term sustainability objectives.

If we drill down to combined heat and power, specifically, we have established for ourselves an internal hurdle rate that our projects need to beat our new combined cycle power plant. And one of the keys to that is high heat utilization. But the important point is that, when you can take advantage of the thermal offsets that you get from displacing boiler fuel, the technologies that are out there today, or at least a subset of the technologies that are out there today, can certainly out perform our best-in-class combined cycle power plant. And the extension of that, in terms of greenhouse gas emissions, is that some of these technologies that are shown here can certainly do better from a greenhouse gas perspective than our combined cycle power plants. But, again, the devil is going to be in the details in terms of how the emissions from the avoided boiler emissions and the losses that you avoid on a boiler get treated in a regulatory standpoint, as it relates to the utility side of this.

COMMISSIONER BYRON: If I may, is that within the utilities' control? Or is that in the ARB's control?

MR. RAWSON: It is within the regulatory proceeding process right now in terms of how that is going to be dealt with, and, of course, SMUD is actively involved in that process in terms of how, for example, plug-in electric hybrids would be dealt with when you are shifting emissions from one sector to another. You could take corollaries from that issue into the CHP arena in terms of how it might be treated for utilities that would want to own and operate combined heat and power projects.

COMMISSIONER BYRON: Thanks for elaborating.

MR. RAWSON: So what I have been up to at SMUD since I left the Energy Commission a couple years ago, is we conducted a technical market opportunity, and I am going to touch a little bit on that, and we spent a fair amount of time and dollars out there meeting with customers, targeted customers that showed up as possible good candidates in our market study, and we have worked with them to do what I would characterize as investment-grade feasibility studies to understand whether or not combined heat and power works for their particular site, and can we extrapolate from that analysis some kind of understanding of maybe their sector within our service territory. And so we -- it is a very in-depth analysis to look at the thermal loads, their electric loads, the coincidence of those, the electric rates that they are paying, the gas rates that they are paying, etc., the costs of the equipment, the CHP equipment, both capital and ongoing, availability incentives, availability of federal tax incentives, different business models in terms of third parties providing those services to leverage some of those tax credits that a publicly-owned utility cannot avail themselves of. And I am going to talk a little bit about some of the high level findings of some of those case studies that we have done.

COMMISSIONER BYRON: Do you mean to tell me you are going and meeting with customers and helping them work these kinds of issues out?

MR. RAWSON: Believe it or not, yes. Yes.

COMMISSIONER BYRON: I am very intrigued.

MR. RAWSON: We have also been working on looking at different business models that SMUD can pursue, depending on whether or not we would want to try to own and operate facilities at customer sites. I will talk a little bit about kind of where we are on that. And we have begun some exploratory work on a combined heat and power program that we might offer to our customers here in the future.

So I am going to touch just real quick on the market assessment that was done in 2006. This is a technical market assessment. We identified about 375 Megawatts of traditional, you know, heat -- displacing heat load, combined heat and power projects. Most of these were in the commercial and institutional sectors, you know, prisons, hospitals, a lot of the same sectors that Ken spoke to this morning in his presentation. When we looked at implementing thermally activated cooling, the potential nearly doubles, and this is all within our service territory. But that is technical potential, you know, and as Ken alluded to in his talk, there is a much smaller subset of that, that is really economically attainable, given the cost of the technology and electric and gas rates, etc.

COMMISSIONER BYRON: Given your substantially lower rates, too. Correct?

MR. RAWSON: Yes. But that aside, I mean, we have identified projects within our service territory that have a positive net present value for the customers. We have identified projects that would have a positive value for SMUD, and this slide here which talks pretty high level about some of the studies that we have done, highlight some of the challenges, even in SMUD service territory where the spark spreads a lot more constrained than it might be in other parts of the state. Food processing is an example of where, yeah, there is definitely a project there that makes sense. If you can kind of look at the trends here, it is these projects on the top that have, you know, pretty good thermal load, high utilization, the one at the bottom, the ones in the middle, you know, data centers, our cooling load, you run into issues there with the efficiency losses of using absorption cooling. Office CHP -- and that is especially true in our service territory where it is competing, really, against really low electric rates that would be used for cooling. Office buildings where it is not really a big load, it is a five-day a week, eight to nine hour load, probably not a good fit for SMUD customers, and a couple of others here. CO_2 emissions, you know, depending on -- this is absent regulatory treatment, but if you just look at the total system CO_2 emission benefits, for the most part, all these projects, if they are done correctly, can provide CO_2 emission benefits. There is one there with an office building. I actually was being conservative and said, really, it is red, but it was basically break even and it is within margin of error on whether or not that is really a negative or not. Another key point that needs to be made, though, is that all of these have the potential to create additional NO_x emissions that need to be dealt with. In the case of the one application, we would be displacing a lot of dispersed boilers and we can do a lot better than the boiler standards for dispersed boilers with larger boilers, so we would realize a NO_x benefit there.

So what have we learned? From a technical standpoint, this is not rocket science. And there are a lot of these technologies out there that are vetted, they have go long history in terms of durability and reliability, and maintenance costs are well understood, but it is a range, some of the technologies are still emerging. But I guess the bottom line is that there are products that our customers can implement, that would make sense for them financially. We think turbines and engines based on our situation are the best fit for most of our customers' needs.

Obvious things, you need to have good coincidence of heat and electric loads, good utilization of the heat is a must. It is the business side of it that has been the thorniest. You know, SMUD has been going through this learning curve like many others would have to do if they are really going to invest time and money like SMUD has, and trying to understand combined heat and power is a solution for our customers. You know, in some ways, we are no different than other utilities, you know, we like big generation, we can control it. One of the comments from the public earlier is that the transaction costs on a per Kilowatt basis are a lot less the bigger you get, so, you know, we have had to struggle with that issue, on how do we do this so that it is cost-effective. You know, owning and operating systems behind a customer's meter, we have had experience doing that in other technology areas and we have kind of moved away from that. There is always this issue about revenue impacts from customers' self-generating. There is the issue about utilities being willing to value capacity, and I think, when I talk about our feed-in tariff, we have made some headway on that issue, in particular.

So the kind of next steps is really in the business model and program designing area. Our Executive Management has made a decision relative to ownership that, you know, SMUD, our business model has been serving multiple customers with their electricity services. We feel that combined heat and power projects that would serve multiple customers is the appropriate place for us to consider owning and operating combined heat and power projects. That would be applications like district energy where you may want to implement not only combined heat and power, but also thermal energy storage because of the great peak load reduction benefit that it provides. And for customers that want to own and operate combined heat and power projects at single customer sites, you know, we are going to try to provide incentives and technical assistance to our customers to help them make the right decision on the technologies that they would implement. Basically, you know, we want to help our customers not get fleeced into buying something that is not going to deliver the benefits that are professed.

So on district energy, we have been looking at a couple of district energy opportunities within our service territory. The first one that we have looked at does not look like it is going to work for us, but there are other large mixed use developments now that we are engaged in the developer and trying to understand whether or not district energy would be a good solution for them to meet some of their sustainability objectives in parallel with helping us. And on the program design side of it, I am going to talk in a little more detail about feed-in tariffs in a second, but we have been doing a lot of looking around the country, we have been talking to other organizations such as USEPA and NYSERDA, we have been talking to other utilities, Austin Energy, for example, that has had combined heat and power, distributed energy projects, for years. We have been talking to third-party providers such as Burns & McDonnell, that is going to speak a little bit later, and others. And we have continued our R&D activities to help us better understand in a more granular way the locational value of combined heat and power, and distributed generation and storage and demand response in our system.

So a little bit on the feed-in tariff. I do have to caveat one little statement in Ken's talk earlier today, he said that the prices have been -- I think the word he said, have been approved for our feed-in tariff. Actually, our tariff has been approved by our Board, we have not published the prices yet, we have been presenting illustrative prices, I will say, example prices. I actually included a couple of tables from that, we could look at that if you would like to, in some of the back-up material. But right now, we are in the implementation stage for getting our feed-in tariff ready to go by January of this coming year when it takes effect. We had our first implementation meeting. This is going to affect multiple business units within SMUD, and we want to make sure we do it right. We want to make sure that we come up with a standard offer contract that customers can be assured is consistent because we want to try to provide certainty to customers that are going to go out and try to get financing from the financial institutions to do these projects. But, hey, they have got a utility that is going to purchase that energy at a set price for whatever term that particular project wants to entertain.

So a couple specifics about the feed-in tariff. It is actually -- we call it our distributed generation feed-in tariff. The construct for it is the same whether it is natural gas-fired combined heat and power, or it is a renewable energy project. It has to be interconnected to our system. We have limited it to 5 Megawatts, or smaller. And we have used definitions for what we define as combined heat and power, or renewable generation facility, that are consistent with AB 1613 or the Energy Commission's definitions for renewable facilities. We have also capped it initially here for 100 Megawatts, so that we can learn whether or not we have got it right, or if we need to make tweaks to it. And, as I mentioned, we will be posting these prices probably in the late fall, late part of the year for people to see.

COMMISSIONER BYRON: How much does 100 Megawatts represent of your system load?

MR. RAWSON: Our peak load is about -- our new peak load is about 3,300, so 100 Megawatts is not a lot, but….

A little bit about the tariff structure. The prices vary according to the year that the system becomes operational. When you give customers options, they can pick different contract terms, they can pick 10, 15, or 20-year terms, depending on, you know, what kind of risk tolerance they have. And we also have the prices differentiated by time of delivery, so on our super peak, the prices are much higher than they are going to be in winter off-peak, for example. The way that we came up with these prices is they reflect underlying marginal costs for comparable power that we would have to go procure in the absence of the projects. And they include the market energy price, including losses, ancillary services, generation capacity, transmission capacity, and sub-transmission capacity. So all those elements go into the combined heat and power feed-in tariff, and then we add in two other cost components for renewable energy projects, the cost offsets for avoided greenhouse gas emissions, and the risk avoidance for volatility and gas prices in the future are included for renewable projects.

I mentioned that we have been in discussions with a variety of different people at the State and national level, and other states, about different incentive models, and I wanted to touch a little bit on kind of where the staff thinking is right now on these different structures. Feed-in tariff, of course, you are familiar with, as it was laid out in AB 1613, the feed-in tariff and also the pay-as-you-save model that is required by AB 1613. Progress payments is a model that is similar to what NYSERDA does, they pay progress payments through the design construction and then they have an M&V period for the first couple of years of operation, and then there is up front incentives which I would say are more akin to like the SDG&E program. And I think the important thing to point out here relative to this is, when you look at those drivers that I talked about at the beginning of my discussion about peak load reduction being a big issue for us, reliability, greenhouse gas reductions, revenue loss -- sorry for the typo there -- the energy cost savings, and then kind of programmatic things, complexity of the program to administer it, and technical and business risk, each of these different models, you know, have pros and cons. We had implemented a feed-in tariff that is going to take effect this next year. Now, we are looking at whether or not there might be other incentive structures that we may want to pursue, depending on where things go from a regulatory standpoint in terms of trying to promote combined heat and power. From this staff personal perspective, I would lean towards kind of a progress payment structure because it ensures that you are going to have some level of performance certainty for that system once it is put in, and we have heard numerous times over the years about projects getting incentive and put in place, and not really delivering the benefits that they were promised from those projects. So that is one way. I am not saying that NYSERDA's model is the only way to do that, but I think it is critical to have a structure where you are going to ensure that there is some kind of third-party element of review of the design to make sure that it makes sense for the customer, and that there is some kind of M&V activity related to making sure it delivers.

COMMISSIONER BYRON: Mr. Rawson, just so everybody knows, and I start with New York State --

MR. RAWSON: Sorry.

COMMISSIONER BYRON: -- and what kind of agency it is, so they will understand why there are maintenance payments.

MR. RAWSON: NYSERDA -- New York State -- they are like PIER if you want to think of it in simple terms, and they provide -- except that, in addition to doing research, they provide incentives for technology implementation in New York, they are not a utility. I belabored that slide, so I will move on. I think the last point I was going to make here about continuing our research and development activities, just before I came on board at SMUD, SMUD had finished a project with a company called Optimal Technologies, this is a technology approach that this Commission has invested a lot of dollars in trying to move forward, and the essence of their approach is to be able to integrate transmission and distribution system modeling into a single electrical model so that you can do optimization analysis on where you are going to get the most benefit, system benefit, where that is loss reduction, reducing voltage variability, etc. etc., from strategic placements of not only distributed generation/combined heat and power, but also things like demand response of load control, perhaps distribution automation, distributed storage, etc. etc., all seem kind of typical non-wire solutions. We did a study back in 2006, we just looked at our transmission system, and we learned some very interesting things from that analysis. And we actually used the results of that analysis in some of our decision making on capacitor additions that we made to our system. Where we want to go from here in 2009-2010 is we want to expand that effort for distributed generation and demand response and storage. We want to learn from the work that the Energy Commission has funded with Southern California Edison, with a company called New Power Technologies and Optimal Technologies. We are going to take the work that we did before on our transmission model and we are going to upgrade it, update that analysis as our systems changed since 2006, like all utilities would profess. We are going to integrate our distribution system into that. And we are going to do some optimization analysis and try to identify where on our system we can get the most benefit from these distributed sources. Then, the last part of that is, you know, we are going to compare the cost of those technologies to what we would have to do otherwise with traditional wire solutions to come up with a way to value the locational benefit of the distributed storage and distributed generation/combined heat and power.

So some of the key takeaways from this real high level discussion that I have provided today is that, you know, doing combined heat and power is not a simple thing. You have to get out and talk to your customers, you have to invest time and dollars in working with your customers to do feasibility studies so that there are not these high level swags at whether or not, you know, combined heat and power makes sense for them, because the devil really is in the details. You know, I showed you some of the case study results and some of those sectors, if you will, sounded great based on our tactical analysis, but when you got right down into the weeds and looked at their financials and their loads, and those kinds of things, those projects do not make sense. And so that leaves me to kind of another key takeaway I wanted to leave, which is, you know, when the state is looking at policies relative to combined heat and power, whether it be, you know, setting targets, or portfolio standards, or what have you, it is really important to recognize the mix of the customers that the utilities are serving because we do not have oil refineries in our service territory, and to make blanket requirements on all the utilities about trying to penetrate even, say, certain sectors, I think, is going to be difficult. The preference would be to state what the objective is, what is the end target; if it is carbon emissions reductions, leave us the flexibility to meet those objectives through a portfolio approach that makes sense for our customers. And I would say that that is applicable also for combined heat and power, given the size of the industrial sector, and how that is changing within our service territory. And I will stop there.

COMMISSIONER BYRON: Thanks, Mr. Rawson. A couple comments to quick questions. First of all, excellent presentation, it is incredible, the stark contrast of the approach that SMUD has taken here. I am also glad to see your considerable expertise taken from the Commission speaks so well of SMUD. And, congratulations, you have set the standard now, you have a tariff that, when I saw it a month or so ago, it made -- it is two pages long and it makes perfectly good sense. And I am very hopeful that some of that will be useful and helpful to our friends at the PUC, that are struggling with this very issue on behalf of the investor-owned utilities. Two quick questions. Do you feel compelled to comply with the AB 1613 requirements? Or are you doing it voluntarily?

MR. RAWSON: We did the feed-in tariffs specifically to address the requirements set forth in there, so, yeah, I would say we do.

COMMISSIONER BYRON: Are you seeing any other interest on the part of your fellow publicly-owned utilities in what you have done?

MR. RAWSON: Not yet. You know, we just -- that press release I showed you was dated the 17th --

COMMISSIONER BYRON: July 17th.

MR. RAWSON: Yeah. So -- but we have been getting a lot of phone calls about the feed-in tariff. You know, I am part of a broader team of people at SMUD that have worked on that, it was really led by our renewable folks, John Bertolino, and he has been fielding a lot of inquiries from a lot of different folks, and I do not know what mixture that is of publicly-owned utilities vs. developers and whatnot.

COMMISSIONER BYRON: Okay, good.

MR. RAWSON: And, you know, our view on that is we put a stake in the ground. I mean, I am not going to say that we have done it exactly right. We have got a lot of implementation work to do between now and January, you know, we have got to come up with a standard offer contract, you know, it is not going to fit on a postcard, but it is not going to be, you know, a ream of papers for a customer to implement a project for the fit. So we have got a lot of work internally.

COMMISSIONER BYRON: Doing that, I think, we will be extremely interested in seeing it compared to what is coming out of the party negotiations for standard offer contract of the PUC. Mr. Rawson, thank you. I would love to ask you more, but we have got two more very good presentations we need to get to.

MR. RAWSON: Thanks for letting me off the hook. Thanks.

COMMISSIONER BYRON: Thank you.

MS. KELLY: The next two speakers, actually, I just wanted to say that I was doing some looking on the Internet, I was Googling, and I was trying to find, you know, people who are using CHP, and leveraging opportunities. And, actually, the next speaker, Bob Marshall, I -- the Energy Commission used to have a co-op program here, and when we had Direct Access and the

Commission -- I had a program with another person, and we worked with the Rural Electric Co-ops, and we went out and we -- there was the California Electric User Co-op, which was an ad co-op, was developed to access Direct Access, and an independent oil producer, COPE, was another co-op, and that is when I first met Bob. But when I went on the Internet, I was not expecting to see Bob's name, and I noticed that, under CHP, that there were two things that were interesting, 1) we know there is a lot of interest in prison, CHP seems to be a good fit for prisons, and so when I Googled, I found that Bob Marshall up at Plumas Sierra, had developed a 6 Megawatt C ORS [phonetic] in the process of developing a 6 Megawatt CHP project at the Susanville Prison. So I thought, well, we just needed to get in touch again and have Bob come and talk about, you know, how a rural electric develops this type of a project, why it is valuable, and I think also the other second part of it is, is working with prisons, whether it is Plumas Sierra, or whether it is third-party or other utilities in the state, this is a rich area, rich with opportunities. So, Bob?

MR. MARSHALL: I am General Manager of Plumas Sierra Rural Electric Cooperative. Our High Sierra project is located at the northern-most part of our system, near Susanville, about 10 miles east of Susanville. And it is a 6 Megawatts, we are a 34 Megawatt peaking utility, our average daily peak runs more like 25, and our average is obviously a bit lower than that, so this is a significant project for us. We are an 8,000 member co-op. Plumas Lassen Sierra County, and we are a two state utility, we serve about 300 customers over in Washoe County. We do not serve the metropolis' of Quincey or Portola or Loyalton or Susanville, we serve around them. We got the leftovers. Because we are an REA, '37, we formed from the New Deal. And we have a true -- we are a true co-op, we have a seven member Board, the community elects the people to our Board at an annual meeting, with over a thousand of our members attending. The physicality of our system is a bit hard to see on the map there. The physicality of our system does actually drive a lot of our decision making. We have the Caribou powerhouse which is this PG&E territory up there, that is where we get our power from, delivered physically. It comes on 35 miles of skinny old transmission line on the side of a canyon, and so, of course, when the bad winters come, they get knocked down, we get knocked down. We then stick all of our load, three prisons and an army base, at the end of that, so we run a 69 K V line 120 miles and stick all of the load on the end. Eventually, that does not work. Lassen MUD sold us an army base and a prison, and we took it knowing full well we did not exactly have the voltage to support it, and that we would figure something out sooner or later. Back in 2002, we were, as the power crisis ebbed, we had done reasonably well in that process, but we looked at our generation needs and realized that we were going to lose a significant contract, and we had to replace that energy. Everybody else at NCPA, the Northern California Power Agency, seemed somewhat frozen in place at the time -- but that has changed -- and we looked at a cooperative research network report that showed that engines had gone from 25 percent efficiency up into the 40s in efficiency, and also for us, the key attribute is they run well at altitude. Now, there is a 28 Megawatt where a zeal is running over at Denver, and we looked at that and said turbines de-rate with altitude, and we are at 4,000-feet for a lot of our territory. So, like I say, it is a 2-3 Megawatt Jennbacher engines, they are at efficiencies probably around 41 percent, so we start a lot bigger. We had a Lassen done ourselves in the project, and as we did the data and looked at how much heat load really was at the prisons, we decided that the two 3-Megawatt Jennbachers would be good. A key thing has changed in the business for us; originally it was 7 Megawatt, 8 Megawatt Wartsila's that had that efficiency, by the time we went to bid, the size, the efficiencies had -- you can get a very efficient engine at 3 Megawatts now, not back at 7 Megawatts, and that is a huge change for us. We have it billed for, we have the air permits for expansion, and the lease for expansion if the prison system grows. The hospital issue -- actually, the hospital bed issue -- in the prison system would affect us. We are a logical place for that. And if there is a expansion of the prison system up there, we would add a third engine. The system is interconnected and, actually, going back, for us, the voltage and reliability were both key things. The brown area to your right is Nevada. I love Google Maps because they took a nice green picture of California probably in June and then took a nice fall picture of Nevada, it is not quite that split there, we do have some access used from power, but our primary power supply is from the west, and that has absolutely been a crucial thing for us to solve. So this is a wholesale power play for us. This is we take the power off the engines, it comes back into our system, then loops the substation and goes back to state prisons. The state prisons are one-quarter of our load. We have a very good relationship with them. We did a rebate at the end of 2000, they got their share of that rebate. We have done a good job with them and they have a lot of trust between us. We tested some of that trust across the last two years on this project.

So the deal we had with them is that the state assumed -- their boilers were 100 percent efficient. We all know, of course, they are not, and, in fact, the older boilers were probably at 75 percent. But the state has dealt with other co-generation projects and they have been burned with efficiencies that are estimate, and we will figure it out later, they were worried that we would not have our engines on enough and they would have to be running the boilers on low, on stand-by, and they thought that they were not going to get that, so we haggled and we give them heat at 90 percent of the agreed to index price. And for us, it is also a -- neither party has to perform. We do not have to run our engines, and they do not have to take our power if they do not need it. So that -- you have to be careful at that point. The good news is that they have a heat load for seven months and that will take up all the heat of both engines. Then we get to fall and spring and we have a base load plant providing hot water for laundry and for general hot water. So one of our engines goes to simple cycle. We can take in the fall -- in the spring, take one engine, overhaul it, get to the fall, take the other engine off line, overhaul that, so we have actual time where you have a month to pull everything in the air, and you do not have hours to get it back online, you have got some time in case you find real problems.

Obstacles -- this was unique. We are building between two state prisons on prison property, equidistant between the two boiler houses. The Department of

Corrections, who is much easier to work with than General Services, but they had some baggage coming from private development, the system savings were never what they said, did not materialize, their operational issues, so we had to work through them and educate people upstream from our counterparts that this is a base load project for us, basically, and we must maintain it, we have a 20-year loan with the rogue utility services, so we are not going to walk away from this once the efficiency drops, we are going to be rebuilding it as we go. Then came the Department of General Services. They wanted it done DGS way and all of the agency here understand that you cannot always win a lot of fights with them. But we have -- and I will talk about that -- we did finally get a good lease with them, but developing this was one of the biggest pieces.

The second obstacle was the cost escalation. We decided to build right when the Chinese economy took off, cost of cement, steel, copper, aluminum, all shot through the roof. Our original price assumption was $11 million for 7 Megawatts. The bids came in at $20 million for 6. That is over $3,000 a kW. But there are some factors that make our system geography unique. The line loss on the end of our system is at 10 percent. The California ISO has done MRTU, we are short of local capacity by their definitions. AB 32 passed. So, given all that, we looked and said, "All right, we can't actually make this work." Among the other obstacles for us, though, is regulatory uncertainty. AB 32 passed, but the Regs were yet to be written, and making sure we get the CO_2 credit has been a key piece. NO_x, SO_x, the other part is the Feds are writing the Bills as we speak. And who gets the credit for it, will this count for us? And those questions were one of the things we had to overcome.

The last one, I think, is how clean is good enough? And the state agency, the CDCR, really wanted this to be a very green project, and they wanted us to meet the South Coast Air Quality Management District standards -- which standard? As of what date? And so this became somewhat of a moving target. Actually, when the South Coast almost made such tough standards that there are no ICEs going in down there, that it actually made it easier to come to an agreement on what kind we wanted.

Again, the frustrations you have is that, when we fought with DGS, and that is a fair statement, we had sort of a head butt contest, and eventually we lost and gave in and just did it their way, you know, we had to be persistent. The AQMD, it all got signed off. We signed -- the deadline for EMCOR, the Fortune 500 company doing this, was December 31st, 2008; we got it signed down here 30 hours before, on the 30th, right at the close of business, so we beat the deadline -- that was a bit hairy. We went back through and the cost escalation piece, we had to weigh a lot of factors in. One of the solutions was that we had to do something; our system stops running eventually. And so the first $4 million of our capital costs was really the cost of cats in the can. We are going to do something and we are going to run Caterpillars on mobiles hooked up to our system, or else we were going to do this project. So you add everything in and the project came back in as tipping to the good. For us, again, this is Plumas and Lassen County, people like independence, they really like being able to be free of the rest of the Grid, and even when we said this is going to be expensive, the membership of our co-op said, "We want to control our destiny."

Regulatory uncertainty -- this is one of the things that we -- we had a fairly decent risk tolerance. Our co-op has sort of -- it is about the size of the dog and the fight, sort of the dog and the fight attitude, and we had more of that post-2001, not quite so much at the moment, and we do not think anybody else would take the risks that we took on the regulatory piece. I mean, in our case, we had to do something, so that helped. But, you know, we watch today -- someone is talking of changing the 1,100 pounds requirement to 985; well, everyone who started a project between AB 32 passing and that draft possible regulation is probably having some heartburn about that.

You cannot keep changing the target. People will not build. People who put their careers on the line, if all of a sudden you build $20 million and it cannot run, it can only run as a peaker plant, not a base load plant, the next manager will have no risk tolerance. So you have got to take care of the early adopters, you have got to make the credits for greenhouse gas under Air Resource Board, you have got to make the credits transferable, sellable, you have really got to make this -- if you do the right thing, you will get rewarded, and that has to be the principle -- if you get bogged into the details of, "Nope, you did not cross your T's right, you missed the deadline by a day, sorry, you're gone," that is a hell of a discouragement for anyone trying to do the right thing.

Solutions -- when we got with the State on the air resources issue, one of the points I want to make, these engines are very clean, NO_x of .074 grams per horsepower per hour; CO_2 .1, and that met the draft rules of the South Coast Air Quality '07 Regs. The pictures up there, that is a state prison in the background, and that is the engine, the mufflers, the radiators, the engines are in white, they are under wraps, they have actually been -- that is the day after we got them there -- stress is watching the engine being lowered onto the bolts and praying to God that the bolts -- that someone actually did not just mention the sides, they measured from the corners, and the bolts actually will go through the holes the way they are supposed to go to be bolted down. In our history, we had a substation where they pulled in the transformer and someone, believe it or not, had not measured corner to corner, and it did not fit.

COMMISSIONER BYRON: Mr. Marshall, that is just when you cut the bolts off, then, isn't it?

MR. MARSHALL: That is what we did, actually. So that is the size and, again, first, you know, up there we were like, "Who cares how much noise it makes?" Actually, of course, the prisoners have rights and it is -- it meets all the sound requirements, as well as all the air quality requirements. Again, this is the transformer for our substation being lowered into place, and it fit again, as well. Big question for us -- would we do it again? That is really a good question. We do not quite know yet because the engines will hopefully be turning on in December. Rumor has it that we are going to have a '51, '52 winter again, and homes were buried up where we are. In Norden, you could walk from rooftop to rooftop when that happened last time. And we really want this engine on at that point in time because my Board President calls me with a growl in his voice, going, "It would be nice to have the engines right now, wouldn't it?" which happened two years ago. We really would like the engines ready to go in case we have a real big winter. We are only a 72-person staff, and 42 of them are electric, and we learned we really did have too many projects at once. We also tried to avoid the gone-too-far-turn-back trap. Munis and Co-ops are really prone to this because, once you get to a certain point, you hate to admit that maybe this is not the best project, and people put the brave face on and build it anyway. So we did this in steps, but, you know, you are always about $2 million out in a project like this, realizing, "You know, I'm not sure this is the best plan." In our case, though, we had to do it and we are happy we have done this; we believe we will do one more when there is load growth in our system. We have a Federal prison that will be a good candidate for this. Any questions?

COMMISSIONER BYRON: Mr. Marshall, thank you very much. Mr. Marshall was kind enough to brief me earlier on this subject -- I should say, on this project -- and I appreciate your making trips to Sacramento to do so. We do not see Plumas Sierra REC down here very often.

MR. MARSHALL: That is our goal, actually.

COMMISSIONER BYRON: I can understand why. And you really already answered all of my questions, but I think this is another great example from a publicly-owned utility that demonstrates that, when you start from the perspective of "what do our customers need," you can come up with a completely different result. So I appreciate your being here. I apologize, in the interest of time we are going to move on. But I was also interested to hear that prisoners have rights also, even up in Susanville.

MR. MARSHALL: And one last comment. People were talking about the value of combined heat and power. The Union of Concerned Scientists, Brenda Ezekiel, has made the point that, in Denmark, the first thing they did to reduce greenhouse gas was not renewables, it was combined heat and power, and they took the big plants down to diversify across the country. So it is, I think, a very valuable tool. Thanks.

COMMISSIONER BYRON: Thank you. Thank you for coming.

MS. KELLY: Okay, our next speaker is Rod Schwass from Burns & McDonnell, and when I was Googling, one of the other things that I noticed is that --

COMMISSIONER BYRON: Is Googling a verb?

MS. KELLY: I think so, yeah. I also noticed one thing that has interested Art Soinski and Pramod, who are a part of my team, was this issue of hospitals, and CHP, and having hospitals be safe havens, having enough power in hospitals for them to go on for quite a while. And then I noticed that there was partnerships between utilities and third parties, and third parties and customers, and one of the people that was doing a lot of this work was this particular company, Burns and McDonnell, then I found out they were working with Mark Rawson, and invited them to come here today to talk to us about some of the opportunities that third-party developers are looking at for CHP.

COMMISSIONER BYRON: Very good.

MR. SCHWASS: Well, thank you for having me here today, and thank you, Linda, for Googling me. And, yes, we are working with Mark Rawson and SMUD, we are one of their contractors to evaluate CHP projects. But we have also been very involved over the last decade with working with the Department of Energy, EPA, CHP partnership, and others to evaluate CHP projects and participate in several RD&D projects to demonstrate combined heat and power in different applications. We have certainly had a focus on industrial scale co-generation for decades, but have really added a focus on commercial and institutional scale CHP in our work.

And as part of that focus, we have identified what we think are some of the markets in the commercial and institutional area that are best served, or could be best served, by combined heat and power systems, and those include hospitals and research facilities, data center, telecommunications, Department of Defense facilities, universities and colleges, and municipalities and district energy systems. All of these are what you might call campus-type applications, multiple buildings, etc. The Department of Defense, I would note also, they are taking a very hard look at deciding what facilities they are going to pull off the Grid entirely, so we are also looking closely at where CHP might be a fit to support their goal. Not all of their facilities, but I would say a good score or more might be candidates, and I think that is probably something that California will be very interested in, is what is DOD going to do with their facilities. And, as a point of reference, the Department of Defense Science Board Taskforce Report, I believe, of 2008 goes into detail on that.

So we have evaluated, and Linda referred to one of the applications where we think CHP is a good fit, or a best fit, hospitals being among them. And we consider a best user profile as a site that has a strong coincidence between their electrical and thermal loads, that are 24-hour days, seven days a week, year round operations, with low seasonal variations in loads, and high power reliability needs. And as a rule of thumb, and we have done scores of assessments on different sites, if a CHP system would not be operated above about 4,000-hours a year at a site, it typically did not pay out economically, was not economically viable.

Some of the business drivers we discuss with our clients, as they look at CHP projects and consider some of the soft costs, if you will, some of the benefits that are not monetized at this point, include cleaner normal power, having more back-up power, or more reliable back-up power, being able to island from the Grid in the event of natural or manmade disasters. Again, as Linda referred to hospitals, that is something that is very important to them and there are new significant requirements for hospitals to be able to operate, in some cases, up to 96 hours or more off the Grid -- not just electricity, but water, etc. So hospitals are certainly one of our client sectors that is looking hard at combined heat and power.

COMMISSIONER BYRON: Mr. Schwass, I have to just stop you for a second.

MR. SCHWASS: Yes, sir.

COMMISSIONER BYRON: I had not heard business drivers for CHP from the customer's perspective for a long time, so I would like to thank you for bringing this slide forward.

MR. SCHWASS: My pleasure. This is our approach to developing CHP projects, it is not atypical, I think other folks use it. But we generally approach a project by conducting a two to four-week screening analysis to determine at a very high level, is the project technically and economically viable. A two to four-week effort, if it proves that it is, we will proceed with a more detailed site-specific feasibility study, six to eight weeks of effort to really get down to what is the net present value of the project, what is the EIRR, what is the return on investment, and does that make sense from this particular client's business needs. If that plays out so the CHP is considered to be viable, then we will engage in the preliminary design and the follow-on final design and installation phases of the project. So, during the first two phases is really where we get into the financial analysis and, again, determine does the project have a net present value, is there a sufficient return based on client's business goals, and how are they going to fund the project, is it going to be, in the case of the private sector, are they going to sell fund it out of their General Funds, or are they going to go to a third-party, or are they going to take on debt for this project, do they want to outsource it completely and perhaps lease it back from a third-party provider, or just purchase the energy commodities from a third-party provider, or, worst case, it does not pencil out and they put the project on the shelf.

We also refer to this project development methodology, and others do, as well, as a DBFOOM, or Design Build Finance Own Operate and Maintain, and that is really three tracks within the four phased methodology that I described on the previous slide. And basically my point here on this slide is to say that a third-party developer can be brought in to handle all of these various phases of the project, or one, or two, or it could be a mix of services from designing and building, all the way through owning and operating the system, and that is going to vary for each application, each site, each client within different market sectors.

Many of our clients want to consider taking the project off their balance sheet and bringing in a third-party provider as a stakeholder in the project to provide the financing, in particular. It can allow them to do that where our client could then purchase the energy commodity from the off balance sheet system. Our clients are also considering different leasing options, and I will not go into details on these different leasing options, other than to say that a third-party developer can design, develop and operate the system, and a client can purchase the energy commodities in a rent, kind of a rental situation, it is just a straight purchase of energy commodities; or they could take more of a ownership stake and have some sort of capital lease where, at the end of a lease, 20 or 30-year lease, they end up owning the system. So there is a variety of lease options that our clients are looking at, as well.

We are also, wherever we can, we are trying to work with the local utility company, as we are with SMUD.

Mark Rawson referred to Austin Energy and the projects they have been doing, we actually worked with Austin Energy on two CHP projects that were also receiving incentive funding from DOE's CHP Program. So we like to work with the local utility company to see if they can, the owner/operator of the system or, as another alternative, we will try to get ESCo's involved to be the third party developer and owner of the system if that makes sense for our client's situation. And wherever we can, we try to work with public-private partnerships; as I mentioned, we are working quite a bit with the Department of Energy. We also work with USDA and the EPA to bring incentives that they offer, as well, to projects. There are certainly a lot of incentives available in state energy programs. I think there is something like $6 billion from the Recovery Act in various state energy programs, some of which can be applied to combined heat and power projects. I mentioned DOD, as well. We are talking with them to discuss how they would like to privatize, well, they have been privatizing many of their utilities for a number of years. But, in particular, utilities -- we try to work with utilities, and where that has been successful, as with Austin Energy, we are also doing it with Gainesville, regional utilities in Gainesville, Florida. What we find with those utilities are the utilities have taken some time to develop a strategic business model, whether it is centered around a district energy system, or an energy efficiency portfolio, or responding to an RPS, where they have developed that kind of strategic business model, it is friendlier environment for CHP.

This chart shows a typical outsourcing business structure that may be applicable for some of our clients' CHP projects where a third party and other stakeholders, including the customer, would form a limited liability corporation that would be responsible for a fuel procurement O&M, implementation of any energy conservation measures, and design and installation of the CHP system. And then the financing entity would be dealing with the limited liability corporation, again, this is a way to keep the financing off the balance sheet, if you will, where that is appropriate. In all of the cases, though, where a financing entity is involved, they look primarily at the system beneficiary, or the customer's credit, to decide if the project is economically viable for them.

I will not go into a great level of detail on these next few slides that have to do with state and federal programs that are available to support combined heat and power and energy efficiency projects, other than to say that there are a number of tax credits, you know, loan guarantees, and direct grant opportunities, both at the state level and at the federal level, notably at 10 percent investment tax credit for CHP projects at the federal level, currently. The American Recovery and Reinvestment Act obviously has a number of opportunities there, I have just finished seven different applications for clients for some of the $156 million grants that are available from the industrial technology program, and I do not think we will see that level of incentive funding on a regular basis, but I do know that DOE is going to have some more money in '09 and in '10 and '11 for incentivizing CHP projects.

I will not go into any detail on this, other than -- this is a factor our clients are looking at where is greenhouse gas emission regulation going and how is it going to affect their business, and in our opinion it is going to be a benefit to CHP in terms of monetizing emission reductions and allowing our clients who are interested in energy efficiency projects, energy conservation projects, CHP, to take the benefit of those emissions reductions.

As I say, we like to work with utilities wherever we can to implement these projects and create a team with our customers, the utilities, to develop CHP projects, and we think it benefits utilities in terms of some of the things that Mark Rawson referred to earlier, a demand side management. It allows the utility to bring in state-of-the-art technology that may improve their overall generation portfolio, in terms of upgrading their technology. It is useful to utilities for Grid power management, especially on extended parts of their system. And potentially it allows utilities to avoid investment where the Grid is insufficient due to congestion.

We always try to right-size a customer's load before we go in and recommend a certain size or type of CHP system, so we try to get them to look at all of their existing equipment -- chillers, boilers, HVAC, lighting, etc. to determine where can they make within the boundaries of their buildings, their site, where can they make energy efficiency improvements such that they do not have to put a larger on-site energy system in place. And that is certainly something that an ESCo or another third-party development provider can bring to the table. And that is my presentation. I am happy to take any questions.

COMMISSIONER BYRON: That was very good. Did you come -- are you visiting us here from Kansas?

MR. SCHWASS: I am, Kansas City. We are based in Kansas City, but with a couple offices here in California.

COMMISSIONER BYRON: Thank you very much. We have a little bit of time for some questions, well, actually, I feel we have not done that -- let me do this, I just want to draw the following conclusion in that, clearly, there is a value or a need for these third parties, as you refer to them, DBFOOM's. They make a lot of sense. There are moving parts here, things break, they wear out, they need maintenance, you have to operate them, there are some other risks involved, and I always recall most businesses and companies do not own their own garbage trucks, either. So this does make a lot of sense and, clearly, what you have indicated is that there is a lot of action at the federal level, as well, that is going to help companies kind of move in this direction. You said you put in as many as seven applications recently for customers. Were those investor-owned service territories? Or publicly-owned utility service territories?

MR. SCHWASS: Both, those are in both. The universities, colleges, food processing industry, a number of different sectors.

COMMISSIONER BYRON: And those are projects that your company will DBFOOM?

MR. SCHWASS: Exactly, we will move forward as an execution team member if they are funded by DOE. And we really think that, you know, in the near term those kinds of incentives are still necessary to make these projects go forward. We know our clients are sitting on the fence a bit to see, you know, what is going to happen with regulations, GHG regulations, etc. These incentives are causing projects to go forward.

COMMISSIONER BYRON: And you are building an asset base in many different states, then, I take it?

MR. SCHWASS: We are.

COMMISSIONER BYRON: Can you give us a sense of how large that is?

MR. SCHWASS: In terms of how large the --

COMMISSIONER BYRON: Well, Megawatts, perhaps.

MR. SCHWASS: Oh, Megawatts of CHP projects, well, it is a couple hundred Megawatts at this point in terms of ongoing projects. We are doing about 100 Megawatts in Texas, a couple of smaller projects in Florida --

COMMISSIONER BYRON: And how many projects would that represent maybe altogether? A couple dozen?

MR. SCHWASS: Right now, there are four ongoing CHP projects. I wish it was a couple dozen.

COMMISSIONER BYRON: All right. This is very interesting and I am really glad and appreciate very much your coming here to present to us. This offers a whole new option that I hope -- well, let me put it to you as a question -- do you see California as a big opportunity?

MR. SCHWASS: I do. I think for some of the reasons that Mark and others have brought up, there have been some significant business barriers, that is the hardest part of the -- the technology is there, the technology is commercially available, it is the business case that has been a hard nut to crack, but I think if we can crack that, and if we can get some support at the regulatory level, I think there is a lot of opportunity.

COMMISSIONER BYRON: Good point. So the business case is something you concentrate on, but I hope you are paying attention to our regulatory environment.

MR. SCHWASS: Yes.

COMMISSIONER BYRON: I will bet you are. Thank you very much for your presentation. I hope you will be here to answer some additional questions.

MS. KELLY: Okay, our next speaker is Dave Schnaars. He is from Solar Turbines and he is in their Environmental Strategies Division, and he is going to talk about CHP for climate change, and one of the key aspects here is CHP is a solution for today, it is something that we do not have to wait for in the long-term.

MR. SCHNAARS: Thank you, Commissioner, for allowing me to participate in your workshop. For those of you who are not familiar with Solar Turbines, we are a gas turbine manufacturing company located in San Diego. We have been in business for over 80 years. We have put quite a few turbines in countries around the world and have very large operating experience with those turbines. We manufacture turbines in the 1-15 Megawatt range, actually we just introduced a new 22 Megawatt turbine, and we have been in business -- or we have been owned by Caterpillar since 1981.

What I want to do here on this slide is show you how AB 32 and its targets compare with national and international targets that are being discussed, so here on the red line are the historic greenhouse gas emissions for the State of California, it is taken from ARB, the Greenhouse Gas Emissions Inventory, and then here are the targets that are set out in AB 32. And one thing you can obviously notice right off the bat is that, going forward, it is going to be different than what business as usual was, despite all the efforts that have been made in California to reduce energy consumption and improve efficiency, we are on a different slope in the future than we have been on in the past. And something else you might notice, although there is no science to the way I have drawn this green line, the peak occurs somewhere around maybe tomorrow afternoon, or maybe yesterday afternoon, anyway, very close to now. So it is important, I think -- and I try to make this point every opportunity I get to speak to people -- that when you set targets in 2020, and 2050, it does not mean that you can wait until 2018 to do something, you have got to take action very early on in order to be able to bend this curve.

If you look at how AB 32 compares with Waxman-Markey, I have shown here in orange the Waxman-Markey targets. Now, those targets are not specifically for California, those are national targets and, of course, Waxman-Markey is yet to be passed, so they are indicative of where we might be, but you can see, it is comforting to know that, at least we end up in 2050 at the same place. Their near-term target is a little more strict. I have also shown here that the targets that were set for developed countries at the UN Climate Change Conference in Bali in December 2007, so the UN was looking for developed countries reducing emissions 25 to 40 percent to 1990 levels by 2020, and then further there in 2050. Again, we wind up in the same place, but the targets are a little bit stricter here in the short-term. So, while I think AB 32 is aiming in the right direction, we might expect that, in the short-term, there is going to be pressure maybe at least in the national front, and plus the international front to maybe reduce the short-term target further.

When you look at reducing greenhouse gasses, these are the four choices that you have, these are really the only four things you can do. And I want to concentrate on these first two which are where CHP has its biggest play. Before I do that, I want to -- I borrowed a couple of slides here from the Carbon Mitigation Initiative at Princeton University, where two professors, Pacala and Socolo, have looked at this whole problem in terms of wedges. So if you look at this point, the green triangle, which represents the emissions reductions that would have to take place over the next 50 years, you could tackle that green triangle by dividing it up into wedges of 1 Gigaton each, and I wanted to just give you a sense of how much emissions reductions a Gigaton of CO_2 is, and what it would take for various technologies. So if you look at wind energy, it is a million 2-Megawatt windmills or basically 30 times the current capacity we have; if you look at solar energy, it is 5 million acres of solar panels, which is a little bit more than the combined area of Connecticut and Rhode Island, and it is about 700 times what we have got today. You would have to triple the world's nuclear capacity by 2055, and you would have to do it at a rate equivalent to what the expansion was between 1975 and 1990, which was a fast expanding rate of nuclear energy. Our carbon capture and storage would require getting that technology to 800 Gigawatts worth of coal plants, or 1,600 Gigawatts worth of natural gas plants. There are three storage projects in the world today that are over a million tons of CO_2 and we need about 3,500 of those kinds of plants, and that would give us an equivalent flow of CO_2 into stored facilities equal to the oil that is being taken out of the earth today, so all these technologies are going to be important. They are not all immediately deployable today and some of them are not deployable at all today, and the ones that are can be deployed at a fast enough rate to help us bend that curve that I showed you earlier, and that is why CHP is so important. It is the least intensive of the carbon fuels, as I am sure you know, roughly about half the carbon content of coal, and it is the most efficient use of natural gas. So if we look at the CO_2 emissions from coal as compared to various emissions from natural gas-fired natural gas turbines, you can see over on the far right CHP being a most efficient way to proceed. It is a very attractive technology from that perspective, and it is immediately deployable today.

Some examples. Here is one that Burns & McDonnell and Austin Energy were both involved in. This is a Texas Children's Hospital in Austin, Texas, and it was the first hospital in the world to have obtained a LEED Platinum Status. It has got a 4.6 Megawatt gas turbine providing both cooling and heating. Similar turbine at a California Dairy location in California, Bank of America has also a 4.6 Megawatt gas turbine in what is now the second tallest building in New York City, providing 35 percent to that building's electrical load, and using 50 percent of the energy that a normal skyscraper would use, also expected to achieve LEED Platinum Status. The bulk of our products, that are all manufactured in San Diego, are shipped to countries outside the U.S., this is an example of an installation in Canada, where we have got two of our 5.7 Megawatt gas turbines and an energy plant. And one of our more recent turbines, the Taurus 65, which is the most efficient turbine we manufacture for combined heat and power, here is an installation of that unit at a tire plant in Germany.

Let me just show you a little bit about this Taurus 65, it is a 6.3 Megawatt turbine, it has got about a 33 percent simple cycle efficiency, which is greatly increased in the CHP application to between 84 and 92 percent, depending on the degree to which the waste heat recovery unit is fired, coupled with very low NO_x emissions, so it has some of these other societal benefits that previous speakers spoke about. You can see here the fuel savings that are achievable in a plant designed around this size of an engine. You can save approximately 15 million btu's an hour, and 8,000 tons of CO_2 per year, so it affords both fuel savings, as well as greenhouse gas emissions reductions. Here is another way of looking at that. If you were to build a plant to produce 6.1 Megawatts of electricity, and 9 Megawatts of thermal energy, you could do this through a gas turbine combined cycle central power plant, and a gas boiler. The central power plant might have an efficiency around 45 percent, and produce about 19 tons per year of CO_2, the boiler would produce about 18 tons of CO_2. Same power and heater are available from a Taurus 65 CHP plant with an overall thermal efficiency of 84 percent, and producing only 32 tons of CO_2 per year. So for each 6 Megawatts of power that you can produce in this way, you are saving 8,000 tons of CO_2, so it has got a worthwhile advantage.

So CHP as a solution to climate change has the advantage that it is deployable today, it will buy us the time that we will need for some of these other more sustainable technologies down the road that I showed you earlier, it has quite a bit of flexibility, and can fit a variety of applications. Some of the examples I showed in my presentation, others you have seen in presentations that preceded mine. It has an extremely high efficiency if it is properly designed, and we take full advantage of the thermal capacity of the CHP units, and that efficiency equates directly to greenhouse gas emissions reductions. And it also has a very low criteria pollutant signature, both for NO_x and carbon dioxide, so it is a solution for today, deployable for today, that buys us the time we need to get to the targets that we have set in the future in 2050, and mid-term targets, as well. Thank you very much.

COMMISSIONER BYRON: Well, I suppose that is a pretty good commercial for solar turbines, but it is a great example because it represents some real numbers with regard to the kind of efficiencies that are achievable, and the comparison to particular -- on your slide, I am sorry, they are not numbered, so I guess it would be about slide 17 or 18, particularly with regard to the comparison to combined cycle generation utility grid operation.

MR. SCHNAARS: Right.

COMMISSIONER BYRON: Very good presentation. I do not have any additional questions. I would like to thank you very much for being here. Although I did not -- you effectively scared the bejibbies out of this by showing all this stuff up front, you know, the comparison by what it is going to take to get these GHG reductions. I assume that means the sale of a lot of solar turbines.

MR. SCHNAARS: We will see.

COMMISSIONER BYRON: Thank you.

MR. SCHNAARS: Thank you.

MS. KELLY: Thank you. Our next group presentations, the first one will be by Pramod Kulkarni and he has produced a draft staff white paper on wastewater treatment facilities potential, and then he will introduce two other people, one from Los Angeles, and one from SMUD, one who has got experience with wastewater treatment facilities, and the other who is doing research in that area.

MR. KULKARNI: Thank you, Linda. Good afternoon. As you well know, as we have said so many times today, that the Energy Commission has supported CHP through 2005 and 2007 IEPR and, of course, ARB has also goals for 4,000 Megawatts, 6.7 Megawatt -- I mean, I think it is 6.7 million tons of carbon savings. So naturally we have been looking at various segments which can contribute towards these goals. This morning, you heard about the industrial segment, you heard about the commercial segment, and so about six month ago, the staff decided to focus on the wastewater treatment plants as a segment for potential CHP opportunities. And what made it more interesting is that wastewater treatment plants fit the criteria which Mr. Rod Schwass mentioned earlier, the best customer profile, and plus more. I will say that in a minute, why plus some more. But anyway, the reason is because they are energy intensive, they are 24/7 load, they are year round, they have got a very cost and thermal load, and plus they are very energy intensive, so they do not need to export all the time the power, they can use it at site, and maybe in substitution be cost-effective. So they are a good target to explore as a possibility for expanding CHP capacity in California.

For those who are not familiar with the wastewater treatment plants, this is just a little schematic. I took it down from the Wikipedia, so it is not exactly, you know, an engineer's design or dream, but I think it tells the purpose. The first two top lines, what you see is pre-treatment up to the primary and secondary level. These are common to all the -- most of the waste treatment plants, and if you stop there, the output, or the end product of sewage treatment is basically the sludge, which emits methane and nitrous oxide, which are both contributors to global climate problems. So consequently, this is not the only user, this is a source of carbon GHG gasses which needs a resolution, plus it happens to be a location which can also use energy. And thirdly, sludge can be converted into energy in a cost-effective manner in a combined heat and power plant, thus solving the GHG problem, as well as meeting the site needs. So that is what I meant when I said best user profile plus more, because doing nothing is not an option here, you have got to get rid of the carbon dioxide and do something with it, and the methane, and do something with it.

What you see between these two arrows is what my paper is concerned about, is basically digesting anaerobically the sludge, creating methane and capturing it, and then drying it, water, and it reduces the amount of waste leftover from the pre-treatment and treatment plant, which has to be trucked out. That is another contributor to the carbon dioxide because many of the leftover materials from the landfill gas have to be trucked out to landfills, or for land application, or for composting, so this kind of transportation also adds substantially to the carbon dioxide emissions.

Of the 265 plants in California, 104 of them truck their leftover sewage sludge out of country. There is a substantial amount of trucking involved, so that is the kind of site benefit, if you reduce the sludge to anaerobic digestion, the amount of waste material which has to be trucked out has been substantially reduced.

On the energy and emission impact, it has potential, as well. As I said, we are major energy users and there was 1.8 Megawatt hour of electricity used by the wastewater treatment plants in 2008. And the entire sewage output in California contributes to 2.2 million tons of CO_2 in one year, for the year. So, as you can see, it is energy intensive, it adds to the GHG problem.

About 265 plants with 1 million gallons per day capacity or more flow, and that is the optimum number because below are not economic to look at any kind of digester or even slightly higher than that, up to 3-4 million gallons per day of possibilities. So out of 265 plants, if you combine them, the total outflow is about 3,000 million gallons per day, we can produce 17 million standard cubic feet of gas, which can generate 100 Megawatts through CHP. Of this 100 Megawatts, I must point out, it is the market potential, not the technical potential. The technical potential is about 125 Megawatts. And out of that 117 plants have digesters and only a few of them have combined heat and power. And the current CHP capacity in California is around 25 Megawatts, it does not fluctuate, it has 14 Megawatts, even sometimes higher, but some of the plants have been shut down because of some of the issues regarding regulation and emission permits. I must add that this particular paper was compiled with the help of the industry, I got help from the operators of the waste treatment plant, I got help from the associations from Southern California, from Central Valley, and from Bay Area operators of waste treatment plants. I got data from the EPA Region 9, information from the financiers, and some of the other developers of these systems. So this paper combines information of recent vintage, and the operating practices we had for last few years, in addition. This paper also uses a lot of information from the PIER Program, which has developed some technology and assisting the potential of using dairy manure, food processing waste, and oil and grease from restaurants to codigest with the sludge. So those two projects from PIER also contributed substantially in doing the [inaudible] for this particular project.

What the PIER project found was that co-mixing and digesting the various bio-waste, besides sludge, things like this, food processing waste, and dairy manure, and oil and grease and fats from restaurants, give a substantial boost to gas production. Now, that is quite important for those plants which are not that big, as such, on sludge capacity of the gas production, alone; however, when you do add these bio-waste, it substantially increases the gas production and improves the economics of the CHP possibility at the site. In the short-run, several of the digestives do have excess capacity, but in the long-run, to develop all this market potential, one has to expand the on-site capacity for digesters and some of the infrastructure requirements would need to be added.

And as I said earlier, the technical market potential was based on and funded by the Energy Commission, and the assessment was done by CH2MHill and others. When I say assessment, they did technical as well as market assessment, and on the market assessment, they developed the financial models to see what kind of [indiscernible] would be expected, what was the cost of capital, cost of equipment, cost of the energy which has been displaced. And based on that assessment, the potential for market existence was derived from the technical potential. And the study was done at the pilot plants, in [inaudible] and utilities, which is east of Los Angeles and Riverside, and they were really good and promising results from both these studies. Basically, they proved technical, economical and market feasibility of mixing and co-digesting bio-waste.

So the good news is that this is not CHP for wastewater treatment plants, and especially co-digesting, it is not a solution in such a problem, actually addressing already existing problem, which needs to be solved and for which people are paying good money to haul away the waste. There are about 2,700 dairies in California, but only 12 have operating digesters. And the reason for that is, that it is often difficult to site and make it economically feasible, the relevant digestion at these dairies. Two main problems are, one, is the cost of digesters, themselves, but, second, is getting permits for the shallow water, and that has been one of the major barriers. So the problem still remains, you need to do something with the dairy waste. So the experiments done under the PIER Program and then, where they did it somewhere else, have shown that co-mixing diary waste with the sludge has substantially improved the economics, as well as the feasibility of CHP. Now, there is a high concentration of dairies in Central Valley. I did not include these in my presentation, but in my paper, there is a page which shows the close proximity of many dairies, waste treatment plants, and food processing facilities, so the assessment has been based on not only the economic viability, but also logistic possibility. Is it logistically viable to do co-digestion?

Another area besides dairy manure and food processing is the availability of fats, oil and grease with sludge. This is something fairly new, it is not as commonly practiced, but we have seen that this has changed. There is a study, for example, at Millbrae near San Francisco Airport, where a small digester was taken and it was a study done by Kennedy Jenks, and they added food waste, actually grease from the grease traps, and it had a substantial increase in the production of the gas. Now, that particular thing has been done several other places, as well, such as EB MUD. And, again, the attractiveness of this particular proposition is that this waste is a major problem all over the U.S. in the sewer system, and the grease traps are required, and then what was collected from there was normally taken to the landfill. Having an option to co-digest that with water treatment plant substantially increases the possibility of gas production and CHP capacity.

What you see out here is market potential by co-digesting different bio-waste. The smallest of those are sludge, which is a standard anaerobic digestion and combined heat and power system, delivering power. And this is 95

Megawatts of electric capacity, not thermal, so it is just electric capacity I am talking about right now. And the next one, when you add grease, actually a very small increase in that, and the problem for that is the potential is substantially higher, I am looking at the orange circle right now, and the potential is substantially higher, however, I am afraid that some of the grease and the oils from the restaurants are going to face some competition from people who are making biodiesels. For example, if you have French fries from a fryer in some restaurants, I think a lot of it now is being required -- not required, but sought after by people who are developing biodiesel, so that is the reason, though the [inaudible] substantially, I have reduced the amount of market potential, so the judge is still out on that, how severe the competition would be, would they be worse and go off of the restaurant grease? I do not know yet, but that is the reason why the results are much higher, I reduced the amount substantially here.

The third one is the food processing waste. And that is, again, substantially higher potential, technical, as is market potential, so 200 Megawatts of market potential. Again, many projects in California traditionally are activities looking at using food processing waste because, without a wider place to take care of it, they either take it to the landfill, and there are some issues regarding just letting it digest on site, as well. So that is another segment which is 200 Megawatts. And lastly is the dairy waste, which, when you add in -- and this is all cumulative, so when you add dairy waste, the potential in California is 450 Megawatts of power, which could be dealt up using CHP wastewater treatment plants.

Now, if this is so good, what are the barriers? And there are several barriers, one, at times, sufficient digestive gas production at some treatment plants do not justify the economic [inaudible] of CHP. Now, that might change when you start adding the food waste, or grease, or the dairy manure, but as of now, we have got the sludge alone, sometimes the digestion does not large enough, or there is not sufficient gas to justify a CHP installation. A second issue is the cost of cleaning gas to a level suitable for some generation technologies, it is costly, sometimes uneconomical. For example, micro-turbines, or sometimes fuels that require high degree of clean gasses, and to that extent, IC engines, combustion engines are fairly tolerant, but other technologies which are quite clean, literally clean, but the problem is the cost of cleaning gas is sometimes overwhelming. A third issue is securing air emission permits can become definitely difficult, and that is because sometimes, as earlier in the presentation, we will be changing rules, and that is one of the major problems some of the other persons cited about not going out for CHP, or not exploring it further. Another issue is the different emissions tariffs for flaring and electrical generation. And this has resulted in some of the existing CHP facilities and waste treatment plants shutting down for the time being. And lastly, on-site demand. Luckily, sufficient on-site demand for wastewater treatment plants justify CHP; however, they are sufficiently high, as [inaudible] suggests, as GIP. The possibility is that, you know, let's go do a segment, we might even get regular boost than otherwise may be possible.

So the bottom line is, anyway, I will not go into the policy options because the paper goes in detail and, in the interest of time, I would rather limit my comments to the barriers. And the two barriers which I mentioned are air emission and some other issues, and that unfortunately is, again, in the area of mixing food waste and grease. We have two speakers after me who are going to add each of these issues. The first speaker after -- I should stop here -- are there any questions right now to my presentation?

COMMISSIONER BYRON: Are you done with your presentation?

MR. KULKARNI: Yeah, because I want to keep really quick and give other people the chance to talk.

COMMISSIONER BYRON: Go ahead.

MR. KULKARNI: Okay --

COMMISSIONER BYRON: I would like to comment, though, Mr. Kulkarni. Your work is very good and your paper is available for comment, I take it, from others, as well?

MR. KULKARNI: I am glad you mentioned that because it is a draft paper, and comments from people who want to expand on the subject matter are more than welcome. So our first speaker is Mr. Mark McDannel, he is a Supervising Engineer at L.A. County Sanitation District. He has been responsible for developing the renewable portfolio, as well as managing several facilities and a substantial number of generation assets in California. He has [inaudible] of experience in the industry, and he has got his Masters from University of California, Irvine, and a degree in Engineering. Mr. McDannel.

COMMISSIONER BYRON: Welcome, Mr. McDannel. Thank you for coming.

MR. McDANNEL: Thanks, Pramod, and thanks for the chance to talk to the group here. Just back, before I start, I did not put a separate slide in this, we are a special purpose agency, serve the wastewater solid waste needs of about half the population of Los Angeles County, 5 million residents, so we operate three active landfills, three closed landfills, and 12 wastewater treatment plants.

COMMISSIONER BYRON: Wow.

MR. McDANNEL: So what I will talk about today, our energy and management program, we have a formal energy management program that our Board approved a couple years ago, CHP technologies for digester gas, and then talk specifically about some of our biogas facilities, and then I think the theme of today, challenges and barriers. Just to caution, some of the barriers I have are, you know, industry-wide, some are agency-wide, some come down to me personally in our organization, but I think it is important to understand this full spectrum of barriers.

As I mentioned, we have a formalized Energy Management Program. We generate 120 Megawatts, about 40 Megawatts from waste energy, 80 Megawatts from landfill gas and digester gas at 10 different facilities. So our number one target is to maximize development of our biogas into energy, minimize energy usage, a few years ago we added a full-time energy efficiency management position to my section, minimize procurement costs, maximize sales income. We try to buy our electricity and natural gas as low as we can and keep our rates down by selling our power as high as we can. And part and parcel of this, over the years, and over the decades, we have done a lot of projects to demonstrate new technologies that have lower air emissions. This is a map of our service territory, just to give you an idea. The large green area with all the yellow sewer lines, that is about 400 million gallons a day that all funnels down to our largest plant, the Joint Water Pollution Control Plant in Carson. When I talk about four plants, just understand, I have got 22 Megawatts and 4 million people being served here in Carson, and then on the top half of the map, I have got sub-Megawatt plants in Valencia, Lancaster, and Palmdale, all serving communities of about 100,000 people, each. I mentioned I have been doing it for a while. This is out of our museum, some engines that we operated in 1938, and they were still running until, I believe, the 1980s.

I think you have seen this information before, so I will go through it quickly, just kind of the size range per unit for the four main power production technologies, turbines, engines, fuel cells, and micro-turbines. And to mention just an overview, we have got one of each, or at least one of each, and I would just mention, we have boilers, all of our plants where we have digesters, we have boilers that can run on digester gas to keep the digesters warm. Our flagship station, the Joint Water Pollution Control Plant, is a 22 Megawatt combined heat and power plant that was started up in the 1980s. The engines in red, and I will go into more details on this, I mentioned Valencia was shut down earlier this year, micro-turbine in Lancaster, that is still running after five years, and a fuel cell in Palmdale that was shut down since I drafted this presentation.

Some price ranges here. I will not go into the details, but you see a broad range, and these numbers are probably higher than you might see other places, but these reflect what we have seen on projects that we have, and the biggest variable in this is really the size of the unit. I mentioned a 10 million gallon a day plant that serves 100,000 people does not make enough gas for, you know, even a Megawatt, so you have very low economies of scale. And the fuel cell numbers there, I believe, are pre-SGI funding which would knock those capital numbers in half.

I am an old school guy, I used to work on NO_x control and so I will still throw out these NO_x emissions in this era of greenhouse gasses, but just a reference, this is our entire fleet of landfill gas and digestive gas-fired units, so you can see engines up in the 35-50 ppm range, turbines 25 ppm, we are installing some new solar Mercury 50 turbines in one of our landfills, which is going to push the best available control technology, they are down to about 19 ppm. And then, you can see our two micro-turbine plants, both of them targeting for 9 ppm, Resources tested those and they ran about 3 or 4 ppm, and I think I did the only full source test on a fuel cell when they say zero NO_x or close to it, but that is a real number .05 ppm.

We are going to go into each slide in detail on our plants. I mentioned our flagship facility in Carson. This is -- I rated it at 22 Megawatts; nominally, we have three 9 Megawatt turbines, run two at a time, one in reserve, this plant has about 97-98 percent availability, and just about all the load is served on site. And I think, as Pramod mentioned, wastewater treatment plants have a lot of electricity demands, so sale of export power really has not been an issue to us. We use everything we make.

The Valencia co-generation facility was a 500 Kilowatt engine since the 1980s that met our steam needs at the plant, as well as offsetting our electrical usage. I am going to talk in depth about that a little bit later. In 2004, we started a program at our plants in Lancaster and Palmdale, we call it the Antelope Valley Green Energy Program. We put in an Ingersoll Rand micro-turbine at our Lancaster facility, a combined heat and power. We received the SGIP funding at the time, it was 40 percent of the cost. That plant has been running for about four and a half years, so we envision that that will continue running, pending the cost of the five-year O&M extension that we are waiting for from Ingersoll Rand. We assume that will be financially viable and keep running. Our Palmdale fuel cell project, I mentioned earlier, this was the first, or one of the first digester gas-fired fuel cells that was up and running. It started up December 2004. Again, a demonstration project. We got the SGIP funding. Combined heat and power efficiency is about 73 percent, limited largely -- not so much, but the units was not that efficient, just how much heat demand we had at the plant. About $2 million, and I will go into more details on that and why it was shut down last month. So I mentioned two projects, the Valencia Co-Generation facility, South Coast AQMD, Rule 1110.2 is really, I think I heard earlier, it has been the death of engines in Southern California. I do not believe anybody has bought one since the rule was passed. We had a requirement in February 2009 to put in air to fuel ratio controller with oxygen sensor and, you know, electronic feedback control. I guess the analogy is, if I went back to high school and pulled my '71 Pinto and had to put fuel injection on it, it just cannot be done, so we had to shut that down. And even if we were keeping it running, the limits they have in 2012 require catalyst and gas clean-up, and it probably would not have been cost effective.

COMMISSIONER BYRON: So what are you doing with the Methane?

MR. McDANNEL: I have got a slide on that later. We are flaring most of it right now.

COMMISSIONER BYRON: Oh, that makes sense.

MR. McDANNEL: Yeah. The Palmdale fuel cell has been a good demonstration project. We have learned a lot, the industry learned a lot, and I think, most importantly, fuel cell energy has learned a lot, so they have taken a lot of lessons learned from our unit and put it into their new units, but right now it is not running today, it is really not in condition with all the new upgrades they have to refurbish, so it is not really set for continued commercial operation. So we are looking for replacements at both of these facilities.

I mentioned -- what are we doing at Valencia? The engine shut down. Part of this, you know, knowing the engine was going to be shut down, we had a project to install some new digestive gas-fired boilers so we could at least use all of the digestive gas that we could for the steam on-site. That got tied up on the AQMD permitting moratorium. So, as of today, we are flaring most of our digestive gas, renting a natural gas-fired boiler and firing natural gas to make the steam at the plant. I have heard the term "regulatory gridlock," gridlock implies you cannot move it, it is a morass. We are still trying to struggle, trying to do something, but that is where we are today.

COMMISSIONER BYRON: When you are done, will you make a suggestion as to how we fix that?

MR. McDANNEL: It is a huge issue. If I were at a global, high level, you know, what I hear of Europe with what has turned crazy environmental rules, they do appear to have integrated rules that look at solid waste, water, energy, air, together, so you can look at what is best on a global issue. California has so many different agencies, so many different intervener groups that are single issues, that I do not know that there is an easy fix to California. Your question, what are we doing with the gas? So this is on the left side with the combined heat and power plant service, the right side is where we are today, so the light blue at the top, we were flaring the excess gas before and we were flaring most of it before, you see the big red block in the middle was a gas going to the engines. And for part of the plant heat and mass balance, we are still using some natural gas and some digester gas for the boilers to make the steam for the digesters.

Some numbers that I had somebody on my staff put together. Greenhouse gas emissions, by shutting that engine down and buying replacement power at nominal California values, we are looking at this little plant, an extra ton and a half a year that is being emitted right now. The NO_x -- it turns out the engine and the flare are about the same emissions, so that is not the big deal. A big impact for us and our rate payers, just compared to our baseline, this is costing us about an extra half a million dollars a year. And we have actually a local -- we are the district, so we have about 30 different districts, so there is one district in Santa Clarita Valley that has to absorb this cost among about, as I mentioned, about 200,000 residents.

Replacement projects. You know, this does give me an opportunity at two plants to start with a blank sheet of paper, and I have been talking to vendors, getting -- I will call it general quotes -- to try to see what is possible. Fuel cells, some of the constraints we have are Valencia plant is between the freeway frontage road and the Magic Mountain parking lot, and there is no room for a fuel cell. So that is out. At Palmdale, even with the SGIP funding, the economics are marginal. The micro-turbines, we have gotten quotes from Ingersoll Rand, I believe also from Capstone, the economics, again, are marginal. However, if there were SGIP funding, not "finding" as this slide says, if there were funding available at the rate we had for existing Lancaster facility, that would move micro-turbines into economically viable.

Engines. They are out of the market in South Coast AQMB, and again, it is not just a dollar and cents thing, it is I am not sure we can find a vendor who will guarantee emissions levels and put in a full system to clean out the gas up front, and put catalysts on the back end.

They may be cost-effective for Palmdale, Palmdale is a more rural area that does not have a NO_x issue, so engines are on the table for Palmdale. We are gathering quotes for engines right now. One new issue that, you know, I know the dairies have been looking at, is natural gas conversion, bringing this up to natural gas level, we can put this in the pipeline, sell it to a combine cycle power plant, and they can take our half a Megawatt's worth of gas and make 1 or 1.2 Megawatts, so it is a great system. But economies of scale, again, we are small, we have all those once-in costs of designing the system, interconnection costs -- interconnecting with the utilities is a complex process, it turns out it is the same with a gas company, they have facility studies, they have monitoring requirements. Nobody has really done one yet, but $200,000 to $500,000 worth of gas testing and monitoring to get going, so a bigger plant, I think you could absorb that, but not for these smaller plants.

So what are some of the barriers? The size. A big chunk of the treatment plants out there are serving these cities of 100,000 people or less. That is less than a Megawatt worth of gas, and current economics, it is just tough to justify economically. The next generation of emission rules, South Coast has it in place, it sounds like it is coming to San Joaquin Valley, I do not know the status of the Bay Area. But the engines are the workhorse. There is industry experience. We have not demonstrated these clean-up technologies, and micro-turbines and fuel cells, you know, they have been around for five years, but they are not the 97, 98, 99 percent available machines that engines are, so that is a big issue as an operator, that really impacts your economics. And, again, this is the greenhouse gas versus criteria pollutant policy conflict, and it highlights it, and I do not have an answer for it.

One specific issue that people in this city could help us on is the tradable renewable energy credit market. We are -- the PUC has been working toward approving markets so we can bring these RECs to market. I hear numbers of $.01 to $.03 a Kilowatt hour, those are real numbers. If there were a market, we could factor into a project, count as income, and use to make a project go. The PUC has been holding their decision, waiting on legislation, and we do not know what the legislation is. But right now, without direct market, we cannot bring this renewable power to market, and it is not even counted anywhere in the state to meet the state RPS goals. So that is something that Sacramento could do to us, is get that in place and get that in place quickly. Capital -- economic times are tough. Five years ago, we put in a fuel cell, our chief engineer rounded up the money, distributed it among all of our operating districts, called it a research project, and we developed that. Today, any project that I propose has to have a five-year or less payback, depending on the risk of the project, and then what happens to me personally is, all of the capital at our plants, we are facing upgrades on our wastewater treatment, so all the capital is going to upgrade the wastewater treatment, so five years ago, I could propose a plant and they would find the money; now, I personally have to go out and find the money, too. So that is a barrier, but I think that barrier is also for any agency. The capital from the main district just is not there anymore. And that is it. Open for any questions you might have.

COMMISSIONER BYRON: Mr. McDannel, thank you. You have got a great deal of experience and expertise in this area. I really appreciate you bringing it here to us today.

MR. McDANNEL: Thanks.

COMMISSIONER BYRON: I am going to forego questions and keep moving forward on our schedule. Thank you very much for being here.

MR. McDANNEL: Thanks.

MR. KULKARNI: Thank you, Mark. Our next speaker -- I should point out that the purpose of this session was to have perspective of the people who are the users, or the customers of the biogas digesters. So L.A. County

Sanitation District is, of course, one. You will be surprised to find, even the Sacramento Municipal District, except for the users of digested gas from the Sacramento Region Waste Treatment Plant, so they are kind of wearing two hats, as a utility, as well as a user of digested gas. Ms. Kathleen Ave, is a Project Manager in that once renewable distributed generation technology at SMUD. She is also on the Board for Sacramento Region's Quality Waste Advisory Board. And at present, she is also managing a project that includes a pilot test of co-digested grease, electric food processing waste at Regional Wastewater Plant. This is something which I had mentioned in my presentation, so this is kind of a field a lot of people are looking at, so we look forward to her findings and presentation.

MS. AVE: Thank you. Good afternoon, everyone. It is nice to be with you. Commissioner Byron, thank you for having me. And I want to also thank you on behalf of SMUD for giving Mark Rawson up. We appreciate the sacrifice that you made. I am, in the interest of time, and because Mark covered some of my background material, I am going to move really quickly through this. I do want to thank the team at SRCSD and Brown & Caldwell who have been involved in this pilot project, a huge amount of work and a really great team. So I am going to give you a really quick overview, talk a little bit about the local biomass program, and then get into the details. I do want to hit this foil, *The Conundrum of Abundance*, some of you may have seen this, it was a show at a local art gallery, and I like this when I talk about solid waste because what we are talking about with this project is really a novel use of solid waste, which is the flip side of consumption in our culture, and things being what they are, it is a great tagline. We still bury thousands of Megawatts worth of power in our landfills every year here in California. With the economic downturn, we are seeing much less tonnage coming across the scales at landfills all over the state, and really all over the country. But nonetheless, as the economy picks up again, our challenge will really be to keep those disposal numbers low and find alternative and more productive uses of that waste. One of the ways to do this is with projects like this. And I also want to relate this back to one of the slides that Mark showed, which depicted SMUD's challenge in terms of greenhouse gas emissions reductions over time, and the likely removal from service of some of our co-generation assets. One of the ways that we can keep those in service is by increasing the production of bio-methane in our service district and replacing fossil-based fuel in those assets, and keeping them in service much longer.

COMMISSIONER BYRON: Ms. Ave, most of the presenters here at the Commission do not include Art in their presentations.

MS. AVE: I hope you enjoyed it. There was some food waste in that picture, as well. So let's move really quickly through all of this, since Mark covered it. I will hit on this one -- we do have a local bio-mass program, and the focus of that program is addressing local problem waste, things like dairy manure, grease and food waste, which have either greenhouse gas emissions associated with them, odors, groundwater contamination problems, so our program is really developed to help address those wastes and to develop local sources of renewable energy. And one of the aspects of that program is to leverage existing infrastructure where possible, which is one the things that led to the development of this pilot test at the wastewater treatment plant.

So getting right to our project, just the context of this. Influent volume at California wastewater treatment plants is down relative to population growth in the state. There is anecdotal evidence of that from sanitation districts across the state. It is difficult to measure, but, in general, it is pretty well accepted and known, and so that excess capacity can definitely be put to productive use with projects like this. Fat soils and grease, as

Pramod mentioned, in collection systems, increases costs and sewer back-ups. Co-digestion has been proving cost-effective at multiple wastewater treatment plants. East Bay MUD is the one that is really well known, but they are not even the first of the biggest, but they were not the first, there are others in place -- Riverside, Watsonville, and Central Marin recently approved a plan to develop co-digestion at their treatment plant, as well. So part of that is the use of the excess capacity and, because of the significant increases in bio-gas production and volatile solids destruction that result from co-digestion. And those numbers are based on sort of standard assumptions of what happens when you co-digest. They do not take into account some of the symbiotic relationships that occur, which are observed in practice and in bench tests. Co-digestion seems to be one of those cases where 2 + 2 can = 5, in that material that has been digested previously when it is in the presence, or digested with more energy-rich material, or a material that has not gone through a primary digestion process, we really see the biogas production increase significantly. So it is a big opportunity. And the other aspect of this that is interesting is the fact that food waste and collected brown grease is typically very -- it has a lot of water in the collected material, and food waste itself is about 75 percent water, so that really sort of challenges the notions of that as a solid waste, and it is, rationally speaking, more appropriate to process it through a wastewater treatment plant, which is all about separating liquids from solids. This is -- you probably do not see these too often here, this is the six-inch vitrified clay pipe, the clean one obviously compared. That is not even a completely clogged pipe, but that shows you kind of what some of the operators in the system deal with.

So, in terms of the background of this project, we do generate energy at the Carson Co-Generation Plant, which is located at the wastewater treatment plant down in Elk Grove. The biogas that is produced there is fuel in the duct burner at Carson, that is considered a renewable fuel. We also use wastewater from the plant and, in return, the plant provides steam to the treatment plant for their heating needs and to the Glacier Ice Company, which is co-located at the facility, it drives their refrigerator and compressors for ice production. There is also a bio-cells recycling facility that is co-located with the treatment plant, that takes a portion, a relatively small portion, but some of their bio-solids, and through heat treatment and pelletization, creates a marketable fertilizer product. So these two agencies, SMUD and SRCSD partnered to evaluate new alternatives to increase the biogas production there, to help us achieve our renewable energy goals, to provide new revenue streams to SRCSD, through tip fees, and additional gas sales, and then really to offer an advanced disposal option to local businesses who are, in some cases, traveling pretty far distances across to East Bay, to dump some of this material.

So this, again, utilizes excess capacity at SRCSD, and this is the largest inland water discharger in the state of California. And the objectives were really to demonstrate pumping the food processing and grease waste directly into the digester, rather than putting it through the primary and secondary treatment systems, to test the increase in the gas production and the methane content of the gas, and to monitor the digesters to see what kind of an effect it had on the digestion process, and then test out some of the assumptions that were made in the Economic and Technical Feasibility Studies. So we are in the middle of this test, actually close to the end, the fourth phase of it will start in August. This is a little difficult to follow, but essentially above the red line and to the right is the existing process, whereby fats, oils and grease, they get into the collection system, make their way to the influent structure at the wastewater treatment plant, where they gum up the pumps and the pipes and generally give the operators there a lot of headaches, and then they are put through the primary and secondary treatment processes, so by the time they get to the digesters, they have been through a lot, and the theory here is that injecting that material directly into the digester will allow for more efficient capture of the energy that is inherent in those materials, so that we can capture that methane gas and use it again in the co-gen.

So these are the rules of the parties that have been involved in this project. SRCSD and SMUD are the project stakeholders. Brown & Caldwell has been the Contractor that performed the feasibility studies and developed the test plan. The Operations and Maintenance, as well as the Policy and Planning Group at SRCSD have been very involved, as well. The Sacramento Rendering Company is collecting material and doing deliveries. And then Pepsi and 7-Up are the two local bottlers that we had involved, who were applying their expired soda pop material.

So the pilot study in our case has a test and a control digester. This project was set up as a temporary plant, so it will be dismantled when the study is over. The characteristics of both the digesters are monitored and they maintain the same operational parameters in the two digesters, with the exception of the addition of the experimental feedstock. So phase I was brown grease only, and then we did liquid food processing waste, then we did a mix, and then the fourth phase that we are going to undertake in August is to do a mix with a higher flow rate to better stimulate full scale loading, and they also wanted to do the testing during Nocardia season, when foaming can be a really big problem in wastewater treatment plants. That was not -- because it has been such a mild summer, they were not able to really see the effects of this on foaming.

COMMISSIONER BYRON: Does everybody know what Nocardia season is? Would you mind?

MS. AVE: Nocardia is a strain of bacteria that flourishes when the heat rises, and it is what contributes to foaming, which can cause obviously a lot of mess and operational problems for the folks who run the digesters. It actually, you know, overflows. So, again, this is our pilot that is about an 18,000 gallon double Wallobaker* [phonetic] tank that was leased just for this pilot test. There is a fill connection which is sort of a temporary receiving station, a mixing pump for external mixing, and heating, the heat exchanger uses the plant's hot water to provide heating to the feedstock that is in the storage tank, and then a feedstock pump. It is pretty simple. Again, I did mention that we did feasibility studies in 2006 and 2007, developed the test plant last year, and the Phase 1 of the brown grease testing started in December of last year. I think that was the coldest day of the year, so it was good, actually, because it definitely presented lots of operational issues, so being able to work through those is very valuable. And, as I mentioned, Phase 4 is going to start in August.

So this is a sample of some of the initial data that was gathered for brown grease. The blue line is the control digester, the red line is the test digester, and the boxes, the black boxes, indicate when the grease was loaded. The blue spike is definitely an anomaly, I think that was an air bubble in the flow meter or something. Anyway, you can see the change, the addition of the grease loading has on the digester gas production, so that is brown grease. And this is the liquid food processing waste, or the expired soft drinks. This pattern of immediate gas increase is apparently unusual. I am told that, at other wastewater treatment plants that are doing this type of co-digestion, they do not see this kind of a reaction, and this could change over time as the digester gets -- as the additional materials get incorporated into the digester, the way it reacts to this material will probably change, but this is what we saw for this initial test.

And in terms of the production objective, the biogas yield at this wastewater treatment plant is considered good, it is in the range of 16-21 standard cubic feet per pound of all the solids. And the assumption that our economic feasibility study made was that the biogas production per gallon of feedstock would be 10.8. And then the actual that we have observed so far in this test has varied between zero and 29, so the potential to match or exceed the objective of 10.8 has definitely been observed. I did want to note that the methane and energy content of the biogas has been stable. That was not a factor, a requirement in the economic feasibility study. In order to make this a positive pay-off, it did not have to go up, and we wanted to monitor it, and it turns out that it has been stable, so far.

In terms of other data, and I should note, too, that the final report for the first three phases just came out last week, so we are still really in the process of digesting all this information and it is pretty new -- I know, sorry. But, so far, we have not observed any other issues with the stability of the digesters, the operations and maintenance of them, no increase in siloxane concentration, so far no issues with foaming, but that may change in August, no problems with odors, the bio-cell's characteristics, or the output. So everything else has gone really well. There have been variations in the feedstock assumptions that were made in the feasibility studies; I think that is just indicative of the heterogeneous nature of this type of material, it will probably continue to vary, and that is just one of the things that you have to plan for and deal with when you do projects like this. And then, again, feedstock flow rates were lower than we had hoped for and planned for in our work plan, and that was based on the issues with the timing of deliveries, the available volumes, and intermittent shutdowns due to some of the operational issues that we did encounter. So we are hoping -- it is also related to the temporary nature of this test, and I could talk a little bit more about that later.

So, so far lessons learned. The brown grease definitely presents many challenges. The solids are less concentrated because of the way these materials are removed from the grease traps, and the team observed significant amounts of stratification in the storage tank, even though there was an external mixing and heating system that was added. So there are some issues there. We did, as I mentioned, observe this very rapid increase in the gas production, especially with the soda waste material. Procuring adequate feedstock for a short-term test, we thought -- the folks at SRCSD really wanted to do this pilot test, rather than move straight into a production offering after they conducted the feasibility study, just to make sure that all the characteristics of the system that they have there were well understood, and the impact to that system. But doing this short-term test, it is hard because, in some cases, we did have to ask some of our partners to make modifications at their operations, and to invest in some storage tanks that they may not have had, so those are issues to consider when you plan for these.

And then education and involvement of the waste-water treatment plant staff is really important so that they understand what this is about, what it could result in, and the benefits.

So the next steps for this project, we want to complete this fourth phase, obviously, in August, continue with the data analysis, we do not expect any fatal flaws, conduct the cost estimate, and then basically make a decision as to whether or not to move forward with a full scale facility. And we are also evaluating injecting the biogas that is generated there into our pipeline and sending it down to our Consumnus [phonetic] Power Plant where it can be burned more efficiently, so that is another aspect to this that we are evaluating.

In terms of statewide barriers, Pramod mentioned the fact that a lot of this material is currently landfilled and a relatively low cost of landfill in the short-term, that is certainly a barrier. The collection programs are an enormous barrier. There is established collection for restaurant grease and, in some cases, for liquid food processing waste. For food waste, meaning kind of the stuff that was in that piece of art, there are very few, you know, there are some very prominent examples like the City of San Francisco is going into post-consumer food waste collection, but there are not that many. And so collecting food waste, which also, you know, as a very high energy value, is a big problem and it is one of the reasons why the assumptions made in our study were that we would move forward with the grease and the liquid food processing waste, and hold off on food waste until some of those collection systems are developed.

Co-digestion and solid waste permitting -- there is kind of some gray area there with the Waste Board in terms of the ability or the requirements for solid waste permitting, when you accept food waste at a wastewater treatment plant, so that is a little gray area that needs to be cleaned up. And then emissions have been discussed today. We have heard about -- we do not have this problem here at this plant, but at others around the state that we know of, the conundrum of burning vs. flaring and the clamping down of the Air District limits on NO_x emissions is problematic.

And the last one I wanted to note is effluent and the water permitting, and this is an issue for us if we did get into the wholesale digestion of food waste because food waste is generally high in salts, and that could affect our ability to land apply the final product, as well as the potential issues with the effluent that is discharged into the rivers since it is a freshwater source or body out here, vs. like East Bay MUD which discharges into the Bay with saltwater, so those are some of the issues that we are looking at, coming down the road as we decide whether or not we can make this a permanent offering. So, thank you very much. Any questions?

COMMISSIONER BYRON: Ms. Ave, thank you very much.

MS. AVE: Thank you.

COMMISSIONER BYRON: Absolutely a very successful demonstration project thus far. I hope it continues and goes to scale. Thank you for being here today.

MS. KELLY: Thank you very much. The last panel of the day is going to be led by Avtar Bining, and he is from our Public Interest Energy Research Program, and he is going to introduce a number of people who are going to participate in a discussion about market challenges from the manufacturers' perspective.

MR. BINING: I am Avtar Bining from the Public Interest Energy Research Program of California Energy Commission. And I manage the Research and Development projects on combined heat and power and [inaudible]. And this panel, what we have done is that there are two aspects of combined heat and power, one is the manufacturing site of these systems, and the other is the customers. So what we have here is two groups of members on this panel, one is the manufacturers of [inaudible] engines, gas turbines, micro-turbines, fuel cells, and the combined heat and power complete systems. And the second group is CHP customers who are users of CHP systems. Among the manufactures, we have Eric Wong, who will be representing the engine manufacturers group, the next is Jeff Cox, he is from fuel cell energy and he represents the fuel cells group, especially molten carbonate type of fuel cells, the third is Steve Gillette, he is from Capstone, and he represents the micro-turbines manufacturers. Robert Byron from UTC, he represents the, again, fuel cells group, and another type of fuel cell called Fuels Focus fuel cell, then is David Schnaars, you already listened to him earlier. He is from Solar Turbines, and he represents the slightly larger size gas turbines, and Bill Martini of Tecogen, he represents the CHP complete system and fractures group. Among the CHP customers, we have Cheri Chastain from Sierra Nevada Brewery in Chico, California, and at that site they are using fuel cell CHP system. And the second person from that group is Gordon Watson, hopefully he will be on WebEx, he is at Hitachi Global Storage Technologies in San Jose. They have put together a product using a small micro-turbine integrated with the boiler to make it CHP system. So welcome all of you on the panel, and Eric is number one for his presentation.

MR. WONG: Thank you, Avtar. Good afternoon.

COMMISSIONER BYRON: Mr. Wong, before you proceed, let me just check something. Do we need to check to see if all of our participants are on, or do you have --

MS. KOROSEC: We will have to open the lines when we get to -- after Eric's presentation, because they are not identified by name as call-in users, so we will check with them at that point.

COMMISSIONER BYRON: Okay, thank you. Mr. Wong, please.

MR. WONG: Thank you. Avtar, do we still have five, seven minutes a piece?

MR. BINING: Yes.

MR. WONG: Okay. I want to first say that I am happy to be here and I am making this presentation on behalf of the members of the Engine Manufacturers Association, and I am going to skip the next two slides for the sake of time because some of this has already been heard previously. If you go to the last slide, I am going to concentrate on this slide today because much of what we have heard this morning really addressed many of the boxes I have in blue on the left. And the challenges and opportunities to engines is what I wanted to pick up on from the other presentations this afternoon, particularly on the NO_x limit. I am going to deal with one very quickly here, which is the second box on the bottom, Efficiency and Reliability. For engines, in order to comply with the market forces of competition and with the stringent emission limits to California, we would need continued need and support from the Energy Commission and other agencies like NYSERDA for more high efficiency engines, driving towards more lower capped costs, and we talked about RAMD reliability, availability and maintainability, durability, so the durability and reliability for engines continue to have to improve in order to reduce down times. So I do not want to spend a whole lot on that because I know the Energy Commission is very up to speed on this and does spend lots of money in terms of advanced research and development under the ARICE Program.

I want to move up to the next box and talk about Initial Limits. I have here -- the described NO_x limit is world-class, and it is the most stringent in the world, and it demands an aggressive after-treatment system, and I believe it was Mark McDannel, among others, that squarely put the issue -- you have NO_x vs. greenhouse gas reduction as a tradeoff of each other, and so which -- you know, what it really comes down to from the Air District perspectives, and as far as this Commission's perspective, and where I am going to make a recommendation, is what existing sectors, do you want to squeeze further. And I am going to use the Rule 1110.2, the engine rules adopted in 2008 by South Coast, as the story here. In that proceeding, which took about four years for them to get to the point where they finally adopted it with the engine community active from, say, 2004 through 2008, one of the things we asked the staff to do was to quantify for the Board members, people setting the policy, so that they had enough data in front of them, is to quantify how much NO_x is coming from CHP vs. other sources in the air basin. This is asked in writing. We actually made some calculations of our own, and I think the amount coming from forecasted CHP in the system was less than one percent for NO_x. The response you got back from the District was that NO_x is a regulated source, it comes from a stationary source, they have authority over that, not over mobile sources, and NO_x was a SIP issue for them, and they had to maintain compliance with the SIP, and had to squeeze from all sources. So what I want to do in contrast, then, this is addressed by several of the speakers this morning, or earlier, that Europe did not choose to have more stringent NO_x levels, NO_x limits, because they were really facing this issue of the trade-off. If you pushed NO_x down, you have an engine or, in our case, you have a penalty in the efficiency of the engine, and you end up having higher GHG or CO_3 emissions, so you shove one down, others go up.

And that relationship caused, as I understand it, is this anecdote of evidence I can quote you to the direct document or study, caused the European community to stick with less stringent NO_x levels. Again, I said this is a world class NO_x limit and it is, and it does have consequences to that. So my understanding is that you have to start looking at other sources for NO_x reductions and I do not know the status of that. So squarely for this Commission and the Air Resources Board, and likely the PUC, as well, is this question: Is the Central Station Combined Central Power Plant, which is the benchmark for the CARB 2000 NO_x limit still appropriate today? This was put into Senate Bill 1298, which is a 2001 Bill by then Senator Bowen, and this is the driver for the CARB 2000 limit. So the question has to become, or at least has to be questioned here, because CARB has struggled with this issue, and they will continue to struggle with this issue, I believe. And we are supposed to have a workshop next week in dealing with CHP in the cap and trade program. And how do you promote CHP, 4,000 Megawatts of CHP under AB 32, when you have this issue of NO_x vs. greenhouse gas reductions? It is a huge policy question, I think, for this Commission, in the IEPR, to deal with and struggle with. I mean, we have all kind of touched upon this issue, previous speakers and myself, but squarely, what kind of analysis do you need to help you in the direct task of the decision? And I think this type of analysis, this data, is required to look at how much NO_x is coming from future CHP and vs. all sources and in different air basins. And what are the ones you can squeeze? I mean, there was an article in the Los Angeles Times at one time where President Burke of the South Coast Board of Directors was quoted as saying 80 percent of NO_x comes from mobile sources. And you can draw your own extrapolations from that. So I think I have kind of run through very quickly the points and I think my recommendations of what needs to be looked at, what type of analysis is acquired, I am -- I and the CHP community are very interested and waiting for the other shoe to drop with respect to the Air Resources Board, who is dealing with this question on CHP under a cap and trade program, cap and trade mechanisms. We advocate that combined heat and power be rewarded for their greenhouse gas production, the fact that they are much lower than the benchmark working standard which is the combined cycle gas turbine central station power plant. As to how that gets captured by the Air Resources Board, I do not know, we are going to find that out fairly soon, their workshop which is scheduled for next Monday was postponed and we are waiting for that. And that will conclude my quick presentation. Thank you.

COMMISSIONER BYRON: Very good. Thank you, Mr. Wong.

MR. BINING: Our next speaker is Jeff Cox from Fuel Cell Energy. He is on the WebEx.

MS. KOROSEC: We are opening the lines to see if we can find out which caller he is, he is not identified by name. So, Mr. Cox, if you are there, if you could let us know?

MR. COX: Yeah, can you hear me?

MS. KOROSEC: Yes, we can. Great. Thank you.

MR. COX: Am I on the line here?

MS. KOROSEC: Yeah, go ahead.

MR. COX: Again, my apologies for not being there this afternoon. I am speaking at another event down here in San Diego simultaneous with this one, but I appreciate the opportunity to visit with you today, and also wanted to clarify something that we see quite frequently in the kind of discourse as it relates to CHP, in California, in particular. There has been a tendency in the past to differentiate between fuel cell projects and CHP projects as if they were two totally different scenarios. We have got a total of 49 individual fuel cell power plants currently deployed and operational in California, some of these are stand-alone units, and others are grouped together as a modular approach. But, realistically, with maybe one or two exceptions, virtually all of these are operated as CHP configurations, and I have got to over-simplify things here a little bit, but just for reference for all the attendees, the relationship we typically look at is with one of the conventional combustion technologies, the relationship between electricity and thermal output. You know, typically you are going to get one unit of electricity and two units of heat output vs. the fuel cell, that is inverted, where we have got a few units of electrical output, and one unit of thermal output. So in CHP application, the fuel cells actually are a little bit more focused on the electrical efficiency side and producing more electricity with the same unit of input gas; but that has still allowed us to pursue some very highly efficient CHP opportunities. You know, you heard about one earlier that we had as an early demonstration project at the L.A. County Sanitation District. Again, my thanks to Mark McDannel for his summary of our past performance out there. I wanted to update the attendees on where we stand in comparison to that project. You know, we have done a lot of things differently in the application of fuel cell technology since the day Palmdale Project was deployed for L.A. County. One of the primary things we do when we operate on a renewable biogas source is that we also pipe in natural gas to the fuel cells as an emergency back-up source. One of the primary lessons we learned from our experience in Palmdale was that the digestive gas, itself, either coming from the digester or as it is being prepared for usage in the digestive gas clean-up system, can frequently be interrupted, unlike a reciprocating engine, or some of the other combustion technologies, the fuel cell really is adversely affected by a sudden disruption, gasified. So in California, at least, we insist on having natural gas as a back-up and we can instantly switch over to that alternate fuel source as a temporary measure while the digester gas clean-up system -- well, while the digester itself is being serviced, and that way we can avoid some of the problems that L.A. County experienced with the early demonstrations of their fuel cell. Ultimately, though, that allowed us to demonstrate a much higher level of availability, a higher capacity factor for the fuel cells. We noticed that a few of the biggest drivers for the fuel cell market here are the higher conversion efficiency. For every unit of bio-gas or renewable fuel, we are again able to produce substantially more electricity for that same year and the fuel and, there again, we do that with the lower emissions, as was noted, and particularly the NO_x emissions that L.A. County had displayed in a previous presentation, Eric's. So I think it is a very good fit between conversion of biogas and electricity, between those sources and the fuel cell, and that is why we focus heavily in that market. Nevertheless, we do see that there are a number of good natural gas-fired opportunities in commercial industrial market where air permitting issues have been a limitation. Again, we are -- had a situation right now where we have CARB '07 certification on natural gas, on all of our products here in California; we are going through the process to certify our digester gas, to have the same exemption from your permits, and my guess is there is a little bit of an advantage to overcome some of those barriers that are out there and have been identified with regard to these emissions limitations. And I want to pass it on to the next panelist and provide more time at the end of the presentation for questions.

COMMISSIONER BYRON: Mr. Cox, thank you very much. We appreciate your being able to join us.

MR. BINING: All right, our next panel member is Robert Byron from from UTC. He will talk about fossil gas fuel cells.

MS. KOROSEC: So can we go ahead and open up the lines and see if Mr. Byron is on the line? Mr. Byron, are you there? Apparently, he has not been able to join us.

COMMISSIONER BYRON: That is all right, one Byron is enough.

MR. BINING: All right, we can move to the next panel member, David Schnaars from Solar Turbines, and he will talk about some technical challenges of gas turbines of larger size.

MR. SCHNAARS: Thank you, Avtar. As I discussed earlier, CHP, whether from gas turbines, reciprocating engines, fuel cells, is a fairly readily deployable technology, and many of the challenges that CHP installations face come from other areas, other than the technical arena. But that being said, there are always things being done on the technical front to improve the product and maybe I can discuss a few of those.

First of all, in this state, just about every installation involving a gas turbine, whether in CHP or not, requires selective catalytic reduction in the after-treatment of the exhaust, and often this technology is not attractive to some of the end users due to the ammonia that has to be moved around and dealt with, so one area -- one technical challenge would be to possibly develop a more environmentally friendly re-agent, a means of catalytic reduction to make these installations more palatable. Secondly, in a combined heat and power installation, at least in the case of gas turbines, the emissions from heat recovery, steam, or waste recovery, that unit is fired, are higher than what you would get out of the turbine exhaust itself because the turbine combustion system is generally more advanced in that you would find in a duct burner, in a waste recovery unit, so again there are some technical advancements that could be made for those burners to reduce the criteria pollutant emissions found in those devices. Instead, if you say, "Well, why don't we just deploy these CHP units without firing the duct burners," then you are foregoing the optimal efficiency that you might get from the waste heat recovery, or from the entire CHP system; and in so doing, you would be going for less than optimal efficiency, which would equate to less than maximum greenhouse gas emissions reduction. So you have got a bit of a trade-off, not unlike the one that Eric was talking about, although it is slightly different. But you want an ideal CHP installation, as we have heard earlier today, that wants to follow the thermal load and needs the ability to adjust its thermal output to do so, and so you probably need to allow for the firing of that unit for this load following, and therefore reducing the criteria pollution emissions on the WHR use side, might be an area of focus.

If you look strictly at the gas turbine and you seek to optimize its simple cycle efficiency, so that it can then participate in a combined heat and power installation in an optimal way, you may, in reality, actually sacrifice some of the heat available from the gas turbine exhaust because, in trying to optimize the gas turbine, if, for example, you recuperate the cycle, and you are using some of the heat that might be used to meet the thermal loads for turbine efficiency, and therefore limit the range, though it is a thermal range, in which you could apply that product.

And, finally, if you look at the current level of NO_x emissions from gas turbines, which state-of-the-art varies on the size of the turbine, but it probably would be generally agreed by most manufacturers that we are pretty close to the limit, available from what is known in the industry as dry load NO_x technology, or pre-mixed technology, that, again, that limit varies from the size of the turbine, but it is probably pretty close to as good as we can get with that technology, and other things have been looked at and various manufacturers have programs and progress, but there is not a clear path to the next generation of NO_x emissions, so that is another area where there might be some room for technology to get funding. Thank you.

MR. BINING: Thank you. The next speaker is from Tecogen, Bill Martini. Tecogen is a company that, in fact, is a fleet system and they have done a number of projects in California, and Bill can talk about from complete system point of view.

MR. MARTINI: Are you able to hear me?

MR. BINING: Yes.

MR. MARTINI: Great. I do not know if you would be able to slide up a couple slides, this was the last one. Very good. I am going to let you be my voice remote here. Thank you for including me today. We wanted to speak today on behalf of various models of CHP systems, those less than 500 Kilowatts, and an earlier speaker mentioned that a big portion of future CHP growth is going to come from small systems; well, we are the very bottom edge of the pyramid. Next slide, please. As you can see, the potential greenhouse gas reductions are quite huge because of the type of customers who are going and have good thermal loads, typically nursing homes, schools, community colleges, apartment buildings, hospitals, and so on. A flip side of being small is that, to have viable projects, everything has to be standardized, and the types of end users we are dealing with are fairly unsophisticated, not energy nerds like the rest of us, and so you start plopping five 50-page contracts on their desks and ask for four different types of certifications, the monthly reporting, and you name it, they will quickly wither and lose interest, and go away. So keeping it streamlined is critical for this far edge of the CHP business. Next slide, please.

That is the sample facility at a community college in the Bay Area. You can see the silver part is the catalytic converter, and the black part is the heat recovery on exhaust, but you can see there is a standardization that is required to make a project like that work, now impeding a swimming pool. Next slide, please.

I would say, if we had to compare the technical challenge portion of this with the market challenge portion, I would say that the technical part is the less critical for us. The technology is fairly advanced after 25 years, especially with the new product that was partially supported by the CEC, the inverter-based engine driven CHP module. A lot of the technical difficulties seem to be addressed. Back-up power is accessible, the low emissions, although that envelope keeps getting pushed, it is a fairly practical, serviceable drive. That being said, there are still always tweaks around the margins in terms of maintaining emissions performance at all times, making it not be a deal killer in terms of maintenance costs, you know, developing new Internet-based controls interfaces, the [inaudible] interfaces for finding new applications for air-conditioning, as an earlier speaker mentioned, and finally, always refining the integration with the systems on-site to keep installation costs down because all these systems are payback driven. And so you have always got to be trying to kind of push that. Next slide, please.

This is the last slide. I just wanted to say again that I think the biggest problem for a small CHP is the degree of complexity that makes adoption difficult. I would say our growth over time has mimicked what you saw earlier, a big clump of systems that went out in the mid-

'80s, a lot of them still running, and then market activity ever since has been smaller, and I would say activity has shifted out of California and is more heavily focused in the Northeast. And it is for all the reasons that have been addressed. I think, in addition, there is still some lingering interconnection issues in California. The CEC had a very helpful role for a long time with Rule 21, and electrical interconnection, which can just break a small project. But that certification process is sort of defunct, except for solar inverters and it has left us a little bit at the will of utilities again, which is quite a step backwards. So that is one thing that we are hoping at some point to see some help from the CEC on.

Finally, I just wanted to say that I think California has had good intentions to promote efficiency, but one way it has done it has been by adding so much complexity that a very unlevel playing field has been created for different DG technologies, and so it is always a scramble to try to stay in the game, and the pile of forms that have to be filled out for a small user just have gotten worse and worse. And so I think there is a need to maybe step back and just rationalize what the priorities are in terms of greenhouse gas emissions reductions and economic productivity for the state and these very small users that do not have a lot of other options. So thank you very much.

COMMISSIONER BYRON: Thank you, Mr. Martini. Thank you for being able to join us.

MR. BINING: Yeah. This completes our manufacturers group. And the next group is of CHP customers, and we have our first speaker here from Sierra Nevada Brewery, Cheri Chastain.

MS. CHASTAIN: Thank you. Thank you for having me here today. So I was asked to come in and give our perspective on having had a CHP for several years. We have four fuel cell units, or fuel cell energy units. All three of them now are 300 Kilowatts, so a total of 1.2 Megawatts, and they are coupled with a heat recovery system that is producing steam that we are recycling back into the brewing process. Brewing requires a tremendous amount of heat, so having the added benefit of heat recovery and having a fairly constant supply of it, has been very beneficial for us. We installed them in 2004, they were commissioned in '04, and we took ownership of them in late 2006. We took advantage of some rebates and some tax credits and some incentives, we got a rebate from PG&E through the SGIP. We also have the 30 percent federal tax credit and, at that time, there was a Department of Defense grant, so it was available, so we got some funding from there. So that brought our costs down tremendously, our out-of-pocket costs, which made the economics of this system much more feasible for us to handle. At the time, we were estimating about a six or seven year payback and we are still currently looking at the same payback period, about six or seven years.

The efficiencies of fuel cells has been -- they have met all of their contractual agreements, operating fuel cell units themselves are anywhere from 45 to 50 percent efficiency, but with the heat recovery unit, it adds another 15 percent, so they are operating in the 60 to 65 percent, or so, range of efficiency. I think one of the areas that I have heard a lot today, and I would definitely like to echo that is that, with these types of systems, you definitely need other applications where you need power, a constant supply of power, and heat at the same time, constant 24/7, 365 days a year.

But then, also, another comment that was made today, and I am forgetting who made it, but the variation in temperature is also very important. If you are using the heat for heating purposes in, say, where we are at in Chico, California, we do not have a need for that heat during the summertime, so using it for brewing is obviously a great option for us, but if it were in an application used for heating within a building, say, it would not work out so well.

Something that has been mentioned a lot today, and I would also just like to touch on it, is the greenhouse gas emissions from the fuel cells. The NO_x, we have actually not measured it, so that was interesting to hear Mark talk about that today. But something that I think is lacking in California is some sort of protocol, or some sort of standardized way to report greenhouse gas emissions for a fuel cell installation, or even a CHP installation, in general. Sierra Nevada is in a number of the California Climate Action Registry and also The Climate Registry, TCR, and I have had to re-verify my emissions twice because nobody really knows what to do with an installation like this. So I was told one thing one year, reported it that way, and then was told a different thing the next year, and now I am on a third difference of opinion here. So I think, as businesses and organizations are starting to report their greenhouse gas emissions and start holding themselves accountable for this, and get credits for their reduction efforts, some sort of protocol or standardization needs to be developed. I cannot keep changing it every year. Along those same lines, our fuel cell system is actually, according to the California Climate Action Registry, a source of stationary combustion, which, if you are trying to go to fuel cell installation in, say, the South Coast Air Quality Management District, you are going to have a very hard time placing something that is classified as a stationary combustion. So there are a lot of questions yet to be asked, and a lot of answers yet to be given as far as the greenhouse gas accounting and actual reporting. Testing, you know, is no problem, but when you are actually trying to report it, that is a whole different story.

I think, in general, fuel cell technology has come a long way, especially since we have had the units. We had units probably close to what Mark had down in L.A. We did try to run biogas in our fuel cell system, we have a waste water treatment plant on site with an anaerobic digester and we are recovering our biogas, and we tried a system to run it through our fuel cells. At this point, it has been unsuccessful, so we are currently recovering the biogas and running it through our boilers. It was not a problem of gas quality, trying to run the biogas through the boilers, there was absolutely nothing wrong with the quality, there were two main problems, one of them was the collection system, and the logic and the controls that were installed in that collection system. It was very over-complicated, I think, and there were a lot of control errors that caused just too many issues for the fuel cells. The other problem is production. Our brewing operation dictates the production of biogas, and the brewing production ebbs and flows through the day and through the week, and the fuel cell is like a very constant, steady pressure, steady flow gas to them, so it was not -- and it has not worked out yet for us, we have not given up hope, but at this time it is not functional for us. With that said, I do think that fuel cell technology, and specifically fuel cell energies technology, has come a long way. I feel like I have learned a lot from our installation and a lot from some of the earlier installations. I think there is still more to be learned and still more little bugs that need to be worked out. Our system is not as good as some of the newer installations that they have come out with, so you know, again, I cannot speak to the newer technology and how far exactly they have come, but I have talked with other people who have them and it seems like they have made a lot of improvements in their technology. Thank you for having me here.

COMMISSIONER BYRON: Ms. Chastain, you seem to be a very knowledgeable end use customer around the use of fuel cells. I appreciate very much your being here for the day, and we are privileged to be able to have you. I suspect, I would say, you have a day job, as well. With regard to your comment on the reporting, I do not think this has been worked out completely yet, and we have made some recommendations in our Joint Recommendation with the PUC, to the ARB on how they should handle CHP reporting. If you have the time, I really encourage you to speak out strongly in this area because you are one of the few customers that can really provide some input, and we should listen to it, government should listen to it very carefully, because we are not trying to make this difficult, we are trying to get the accounting correct. I also note my personal observation that your product does emit CO_2 --

MS. CHASTAIN: Correct.

COMMISSIONER BYRON: Yes. And although we do not endorse products or companies at this Commission, I would certain endorse all those that are interested in CHP to consider the product differentiation that you offer, and I will do my part. Thank you for being here.

MS. CHASTAIN: Thank you.

MR. BINING: The last speaker from CHP customers group is Gordon Watson from Hitachi Global Storage Technologies. I hope he is also on WebEx.

MS. KOROSEC: He is on the line, yes. Mr. Watson?

MR. WATSON: Yes. Can you hear me?

MS. KOROSEC: Yes, we can.

MR. WATSON: Okay, good. I am a Flight Mechanical Engineer at Hitachi Global Storage Technologies in San Jose, and we invented the [inaudible] drive here when IBM was a plant. The plant was built in 1957 and we have a fairly large boiler plant where we have steam produced for heat process, scrubbers, and humidity control. The utility plant has five boilers, which are between 18,000 and 36,000. The current load is somewhere between 30,000 and 50,000 pounds per hour. We had one boiler retrofitted in November of 2008, on the 36,000 pound per hour flare, and with an 80 kW micro-turbine. And since we installed it in 2008, we have probably saved on the order of $16,000 in electrical and even gas costs. It has the potential to save us $65,000 per year. The system has had several problems unrelated to the micro-turbine and we have received a new burner micro-turbine and a gas compressor, but we have had problems because the boiler is 20-years-old, and we had a severe problem with vibration on the side walls of the boiler, caused by, we think, the new burner, it is a very low NO_x burner. And I guess one of the characteristics of that particular burner is vibration, the walls were not designed for this new burner, so that had to be stiffened and fixed, so it certainly was not a show stopper, but it caused some delays when we could not run the micro-turbine, or the burner.

In addition, we have had problems with the damper on the forced draft fan, and they are very very poor dampers in the first place, we have found, I guess in commercial grade boilers. So that currently still is a problem and we are working to solve that, probably by putting a BFD. But the bottom line is, I think we are glad to be part of an experiment, and it certainly did not cause us any problems. We think we have learned a lot. We have got an improved boiler. We have saved some money in electricity. And we are looking forward to saving the $65,000 per year in gas and electricity that we should be able to achieve, and we are going to continue working on that. So, unless there are other questions, that is all I have to say.

COMMISSIONER BYRON: Well, that was very short. Mr. Watson, a couple of thoughts come to mind. How is it that you calculate your savings potential that you are not achieving?

MR. WATSON: Those are calculated by the vendor and it was just simply based on the gas savings, not on electricity savings that we would achieve on this project.

COMMISSIONER BYRON: Well, I suppose another way you could achieve more is we could ask the local utility to raise your electric rates, that might --

MR. WATSON: Yeah, that is one unfortunate thing about our site, is we have very good electricity rates because we have a back-up turbine right now. But we do have low rates, and that hurts all of our energy projects.

COMMISSIONER BYRON: Mr. Watson, thank you very much for being with us. I hope you will stay on the line because I think we are going to go to some public comments and questions at this time. Is that correct?

MR. WATSON: I will be happy to stay for a while.

COMMISSIONER BYRON: Thank you.

MS. KOROSEC: Yes.

COMMISSIONER BYRON: Is that all right, Mr. Bining? Should we open it up to questions, or do you have something else you want to do?

MR. BINING: Yeah.

COMMISSIONER BYRON: Go right ahead.

MR. BINING: I just want to interject one more --

COMMISSIONER BYRON: Oh, you have someone else on the line?

MS. KOROSEC: Well, we wanted to check one more time to see if Mr. Byron is on the line. No, he is not.

MR. BINING: All right, then this completes our panels presentations and the floor is open for the public comments on this part of the presentations. Any comments from the floor?

COMMISSIONER BYRON: All right, I hope our panelists will stay. We will just transition into a public comment and question and opportunity period, so if you have a question for the panel, or any other speakers, that is fine; or, if you have a comment, this would be the time to do it.

MR. NICKESON: Yeah, hi. My name is Bob Nickeson and I am from a company, Alzeta in Santa Clara. And it is a question rather than a comment and it is sort of directed at David because he spoke the most about some of the emission technologies for NO_x reduction. I just wondered, because Alzeta is in the lower NO_x business and has done some work in a couple of technologies for duct burners, how valuable, say, an ultra low NO_x duct burner technology would be to systems, for CHP systems, if you thought that was a very valuable technology to pursue?

MR. SCHNAARS: Yeah, I -- certainly, being able to lower the NO_x emissions of a CHP system, or even a gas turbine in simple cycle is valuable. It is an effort that my company has been pursuing since it started making turbines, and all of our competitors are pursuing. And as I mentioned, Bob, we are -- the industry is at a point where we need to start looking at what new technologies might be available because ones that are deployed, commonplace now, are pretty close to the limit of what they are going to be able to do. So we are definitely open to looking at new technologies. Where the difficulty, I think, comes in is that these combustions, even the current drive on NO_x combustion system that is widely deployed, was not a technology that was readily adaptable to current day as it existed before its deployment, it was some considerable modification that needed to be made to the combustion system, and a number of new issues had to be dealt with. The same is going to be true of, I imagine, if we try to tackle some other technologies, they just do not plug into a gas turbine, and we are going to have to modify the turbine, it is going to affect other areas in the turbine, and so there is going to need to be a combined effort between those developing a new combustion process and the actual turbine manufacturers, themselves.

COMMISSIONER BYRON: Very good. And I think Mr. Wong's point earlier merits repeating, and that is I think he used the word "squeezed," how much more are we going to squeeze this particular industry, given the benefits associated with what we are trying to do. So we need to take a more integrative approach here, as well. And I know that there has been a lot of companies that have come and gone, efforts to reduce NO_x, and I agree with you, I think we really are currently at the limit. There is just -- there is a lot of nitrogen in the air, and it has to go somewhere, so, again, thank you for your comment. Mr. Wong, did you want to add anything to that? Okay, thank you. Ms. Burgdorf.

MS. BURGDORF: Hi, Marci Burgdorf with Southern California Edison. I just wanted to make a couple points from a utility perspective. I appreciated hearing all of the case studies and things that are happening in all of the other utilities, POUs, and particularly appreciated the study that was done by ICF, that was very helpful to have gone through that, as well as the study that was done by the staff here. And I want to reiterate the importance that we make in any of our comments, and that is the importance of having efficiency and operating standards, so that CHP can serve as an emission reductions measure. And I do agree with Mark Rawson, who mentioned that, if CHP is done the right way, that it can reduce GHG emissions if it is designed correctly, and I would have to agree with that statement. So we continue in our comments to advocate that there are some benchmark and some efficiency standard that this state has and ensures that we are accomplishing the GHG goals and the environmental goals in the state. It is an important part of AB 1613, we heard very briefly about that today, and we are very excited to be part of providing some of those additional comments. Additionally, Ms. Kahl talked a little bit about the contracting options or, I guess, lack of contracting options, for CHP. And in addition to selling into the market, CHP systems with Southern California Edison also have a couple of other procurement options. We do have power procurement solicitations for new generation, we do have a request for offers for CHP generation, or in generation, and if a CHP system is renewable, it can participate in any of our renewable solicitations or other renewable contracting opportunities. So, for example, we have the 1.5 and under Megawatt feed-in tariff for renewables, so that would be another option for them to participate. Thank you very much.

COMMISSIONER BYRON: Thank you. Mr. Rawson.

MR. RAWSON: Mark Rawson from SMUD again. I wanted to actually build on her comments about performance monitoring, and also reflect a little on your comments about your experience on trying to quantify the greenhouse gas emissions. The Energy Commission has done a lot of good work in partnership with ASERTTI, and Department of Energy, development of standardized protocols for monitoring performance of distributed generation technologies. I think that is a great place to start in terms of moving forward with any kind of M&V on evaluating performance of combining power projects. But, to echo your point about how complicated it is as a customer, you know, we have seen that same experience in our dairy digester projects, the few that we have started here. For that customer to go through the process of understanding what the greenhouse gas benefits are of doing a combined heat and power project with biogas on their own, would be formidable. And I applaud you for trying to wade through that. You know, at SMUD, we have invested a lot of dollars with those particular projects ourselves, to help those customers work through understanding how the new protocols on greenhouse gas monitoring, etc., you know, work, because we are trying to learn as the utility how that process is going to work, so we can replicate those types of projects with other dairy farmers, or other renewable projects throughout the state. So I wanted to encourage you to, you know, leverage the investments that the state has already made on standardized protocols on just the efficiency and performance aspects of combined heat and power, and try to help work out this issue about using the protocols that have been developed by CCAR or others, ASERTTI, as well, for greenhouse gas emissions. But that is an area where customers and utilities need help to understand how all that stuff works. Thank you.

COMMISSIONER BYRON: Thank you. Any other comments or questions? Please.

MR. McCOY: Thank you. My name is Patrick McCoy. I am with the Department of General Services, State of California, currently the Program Manager for the Solar Power Purchase Program. Although it seems like anything that has to do with distributed generation comes across my desk, I know Bob is not here, but I certainly would like to sympathize with Bob Marshall. I, too, have problems with DGS, even though I work with DGS. But I would like to make several comments --

COMMISSIONER BYRON: There is a public record here, you know?

MR. McCOY: I know. I realize that. Hopefully it will motivate somebody to do something. I would like to advocate -- to make three points here. I would like to advocate for -- I think it was mentioned here previously -- some sort of third-party review, or verification when it comes to CHP systems. Back when SGIP first started, we did install several systems that some of us engineers protested because we did not believe that there was any adequate calculations given to thermal matching and, sure enough, those projects were a dismal failure. And it is interesting that, a lot of times, successful projects are discussed, but I am much more interested in the failures because, out of the failures, I think we can learn a lot more, and we certainly have. So the review and the verification is going to be important for us, especially for performance. Our good friends at the Department of Finance, who does have a hand in approving our projects, really have pretty stringent demands upon us in terms of not only demonstrating performance, but demonstrating that, if we are implementing these systems for savings, that the savings actually materialize. And a lot of times, I hear companies, system developers and integrators, talk about savings, and I really question if they really know what they are talking about, or if it is just a marketing pitch. So some sort of third party review would certainly be helpful here. Leading into that, then, is my second point, where I do not know if it is protocols, or standards, it certainly is a technology, but the notion of monitoring, metering, and verifying the delivery of thermal energy. That was certainly one of the failure points in the combined heat and power systems that we have installed, and it has also been very problematic for some of the other large third-party co-gen systems that we have at the facilities. Typically, we are the steam host and the third-party co-gen in selling the power to the utilities; but, just to give you an example, on one of the third-party co-gen projects, as a result of a -- it was a rounding error, we had to bill them for an additional $4 million. I do not know how much we collected, but it was something to that tune. It had to do with a metering error. So the notion is that, inaccurate metering can quickly accrue potentially large, you know, deficits in terms of which side of the ledger are the benefits accruing to, because the metering problem could have been the other way around, and the third party themselves could have been losing revenue in that regard. So the metering and monitoring and the verification of the thermal energy, I think, is important. The last point I would like to make as a representative of a large public sector entity is, you know, funding, or lack of funding, lack of available funding is very problematic for us in terms of pursuing anything like combined heat and power, therefore, we are going to rely upon public private partnerships for the foreseeable future. The Solar Power Purchase Program is predominantly a public private partnership, a third party power purchase agreement type business model. And I think that anything that we do in regards to combined heat and power, to meet the policy goals and objectives and, of course, the mandates under AB 32, will be implemented under a private public partnership type of an approach. What that means is that we have an additional constraint that I am not quite sure how to deal with. I do not think it is within the scope of this particular proceeding, but a lot of public sector entities finance their buildings and facilities with leased revenue bond finance, or tax-exempt bonds, and a lot of problems occur right there. So I just wanted to make this as a matter of record that, I know there is a lot of industry and utility and manufacturers here, that it is a problem. It is tough for us to manage and deal with. And certainly, we internally at the Department of General Services and the Governor's Office, are working on this issue because it could be very prohibitive in terms of us achieving the goals as outlined in AB 32, as long as we pursue the public private partnership type of financing for these systems. That would also include the monetization of these -- I will call them ecstringic values -- the greenhouse gas reductions, whether they be cap and trade. It is very important for us to be able to, once again, be able to clearly demonstrate to the Department of Finance that this is actually a) real, b) it is verified, and c) if there is a revenue stream coming from somewhere, that it be clearly identified and manageable within how we have to manage our business. So it is an important consideration. We have a tough time convincing people. For example, the renewable energy credits with the solar pv systems, unless we are able to clearly monetize those, establish a market that is really transparent and liquid, the Department of Finance just has a difficult time wrapping their minds around it, especially when it does not translate into actual money in the bank, you know, so…. But anyway, those are the points that I wanted to make in regards to this workshop. Thank you.

COMMISSIONER BYRON: Mr. McCoy, thank you. Those are very sophisticated comments and well thought through. I appreciate your being here today.

MS. KOROSEC: Commissioner Byron, with your approval, can we move to the WebEx and see if we have any comments there?

COMMISSIONER BYRON: Sure.

MS. KOROSEC: Let's go ahead and open the lines. All right, does anyone on the line have any comments or questions?

MR. COX: Yeah, we have got one here.

MS. KOROSEC: All right, could you identify yourself, please?

MR. COX: This is Jeff Cox again with Fuel Cell Energy. I just wanted to go back and reinforce a point that Bill Martini from Tecogen made in his presentation about the important work of the Rural 21 Working Group, that the CEC previously hosted. You know, I mentioned in my presentation how many units we deployed here in California, and I want to add that the vast majority of those probably would have never been possible, had it not been for the Rural 21 certification program and the ability that that provided us to circumvent some of the obstacles that we see towards interconnection. And also, I guess, with Marci Burgdorf there, my compliments to SoCal Edison. One of our most recent projects, just to give you a demonstration of the effect of the Rural 21 certification, was seen at the Eastern Municipal Water District, it is a wastewater treatment plant, it was a biogas fuel THP fuel cell opportunity, but we submitted our application to SoCal Edison for interconnection, and it came back approved in three days. Three days for approval of an interconnection, thanks to the Rural 21 certification that we carry. And, again, I think the importance of that program cannot be overstated.

COMMISSIONER BYRON: Very good, Mr. Cox. Ms. Burgdorf stood and took a bow while you were talking. Also, there were some folks in the room earlier that were very much involved in the Rural 21 activities here at the Commission years ago, and I do not see them any longer, but I appreciate your paying tribute to that, as well. We have had difficulty continuing to fund that here at the Commission and, in fact, I believe that has moved in its entirety over to the PUC. Of course, when we talk about Rural 21, that is the Public Utilities Commission rural, and we hope that they will continue to be active in that area. Please.

MR. SEYMOUR: Curtis Seymour from the CPUC. I just would like to make a point about that. We are beginning to look at Rural 21, but the folks who were working on it at the CPUC are new, so please come, contact us, Curtis Seymour, I will make my information available to folks, because we want to get that process moving along and we need your help.

COMMISSIONER BYRON: Very good, Mr. Seymour, thank you. I am sure there are a few folks here that will want to talk to you before you leave.

MS. KOROSEC: Do we have anymore comments on the WebEx?

COMMISSIONER BYRON: All right, we did not mean to foreclose any other comments here from the public. I would ask one last time if anyone has any comments.

MR. SCHNAARS: Commissioner, I would just like to ask Cheri a question. You said that you tried to use the biogas from your process in your CHP system, but the entire [inaudible], did you ever give any thought to lending the biogas and natural gas, and make some more steady stream?

MS. CHASTAIN: The biogas was blended with natural gas constantly. It was covering -- it had the potential to cover about 13 percent of our total consumption within the fuel cell, so it never had the potential to cover 100 percent, it always ran out of blend.

COMMISSIONER BYRON: Thank you. Well, I think we may be here at the close, then. If I could, I would like to offer some closing comments. I hope you could tell, but I was very impressed today with the content and the presentations, the comments that we have received in today's workshop, I think particularly I am very impressed with those who are working so hard to overcome all the barriers that the state has put up to combined heat and power. And I would like to thank some of our end use customers and their representatives that are here today. Going back to the earlier presentations with regard to the market studies, I think they are very well done, although they are not as optimistic as I would like to -- as I would hope they might be; nevertheless, I think it speaks to the independence of those analyses. The assumptions, we know, are extremely key and I want to make sure that we make every effort to resolve the input from some of the folks that spoke here today in how that report finishes in the final results. Again, those are forecasts. I would certainly comment that the PUC and elsewhere, that these numbers should not be used as caps or negotiating tools in contracts with the CHP industry; these are best efforts at forecasts. I think we can tell the economic potential and the technical potential are quite different and there is a big spread between the two. In fact, that leads me to wonder what the difference would be in that actual forecast if we were able to think outside the regulatory lines just a little bit, as some of you have demonstrated here in your presentations today. If all parties were interested in serving the customer needs and working from the perspective, "How can we make CHP a successful market opportunity," I think that forecast might look a little bit different than it does. Clearly, the economics in CHP are not the only factor. I look back to the examples that we got from some of our municipal or publicly owned utility representatives here today. I was struck by the alignment of their corporate goals. I cannot read my own writing, I apologize. I was struck with the alignment of their corporate goals with those energy policies of the state, and the interest in meeting customers' needs. There is a stark difference there, certainly, with the investor-owned community of utilities who have slightly different interests. So I would really like to see us, instead of arguing that customers could be harmed by the cost of CHP, that we really start looking at CHP as a means of lowering rates and greenhouse gases, and as a way of getting others to invest capital in the generation market, rather than that being put on the burden, or on the backs of rate payers. It is extremely interesting to me that in a municipal utility, in the publicly owned utility sector, that CHP projects can work, given that their average rates are about 40 percent lower than those of the investor-owned utilities. And I am going to go just a step further on that because I think it merits some thought here. You know, it does not seem all that long ago that I certainly remember in the electricity sector we had a great deal of difficulty convincing utilities about the benefits of renewables and energy efficiency and now reducing greenhouse gases. But certainly in this state, that being California, that fight is over. And we now embrace renewables and greenhouse gases and energy efficiency as the

REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF,

I have hereunto set my hand this 30th day of July, 2009.

Peter Petty

Peter Petty CER**D493