JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2009 Integrated	) 09-IEP-1G
Energy Policy Report	)
	)
Biopower in California	)
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, APRIL 21, 2009

9:02 A.M.

Reported by:
Peter Petty
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member IEPR Committee

James D. Boyd, Associate Member, IEPR Committee

Julia Levin, Presiding Member, Renewables Committee

ADVISORS PRESENT

Kristy Chew

Susan Brown

STAFF PRESENT

Suzanne Korosec

Jason Orta

Garry O'Neill

Kevin Barker

Kate Zocchetti

Joseph Fleshman

ALSO PRESENT

Steve Kaffka
University of California Davis

Pat Sullivan
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Dave Warner
San Joaquin Valley Air Pollution Control District

Allen Dusault
Sustainable Conservation

Greg Morris
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ALSO PRESENT

Fernando Berton
California Integrated Waste Management Board

Doug Wickizer
California Department of Forestry

Mark Nechodom (via teleconference)
United States Forest Service

Kevin Sullivan
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California Biomass Energy Alliance

Michael Theroux
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Jim Jungwirth
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I N D E X

I N D E X

P R O C E E D I N G S

9:02 a.m.

MS. KOROSEC: Good morning, everyone. I'm Suzanne Korosec. I lead the Energy Commission's Integrated Energy Policy Report Unit. Welcome to today's workshop on meeting the state's biopower goals for electricity generation.

This workshop is being conducted jointly by the Integrated Energy Policy Report Committee and the Renewables Committee.

Just a few housekeeping items before we get started. For those of you who have not been here before, the restrooms are out the double doors and to your left. There's 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 evacuate the building, please follow the staff out of the building to the park kitty-corner and wait there for the all-clear signal.

Today's workshop is being broadcast through our WebEx conferencing system. And instructions on how to participate are provided in the workshop notice for today's event, which is available on our website at www.energy.ca.gov.

The workshop is also being webcast, and access to the webcast is also available from our website.

Today's workshop relates to Governor Schwarzenegger's executive order S-0606 which set targets for the production and use of biofuels for transportation and electricity from biomass.

In the Governor's executive order the Energy Commission is required to report on the progress towards these biomass goals every two years in the Integrated Energy Policy Report.

For those of you not familiar with that report, we're required to prepare this report every two years. It provides an overview of major energy trends and issues that are facing the state. And we conduct an extensive public process to get input on the topics to be covered in the report.

The Energy Commission's Integrated Energy Policy Report and Transportation Committees held a joint IEPR workshop focused on the biofuels component on January 13th. And today's workshop focuses on the electricity side of the issue, including the progress that's been made toward reaching the Governor's goal of meeting 20 percent of California's renewable portfolio standard using biomass and biogas. And also the challenges facing our ability to meet that goal.

So, with that brief introduction, I'll turn it over to the Commissioners for opening comments.

PRESIDING MEMBER BYRON: Thank you, Ms. Korosec. Good morning, everyone. My name is Jeff Byron. I'm the Presiding Member of the Integrated Energy Policy Report Committee, along with my Associate Member, Vice Chairman Boyd, to my left. To my right is Commissioner Levin, who is on the Renewables Committee. And I'm not sure if our Chairman will be joining us, but she's also on the Renewables Committee and listed on the agenda today, as well. All the way to my right is my illustrious Advisor, Kristy Chew.

This is another very interesting staff workshop on renewables. We're very interested in public input. There's a number of key questions that the staff has asked. I think Suzanne's going to keep track of how many IEPR workshops we're going to have all this year, but there's going to be a number of them. And this one's extremely important to us.

I'd like to ask if either of my fellow

Commissioners would care to make any comments. And then we'll proceed. Commissioner Boyd?

ASSOCIATE MEMBER BOYD: Very briefly. Appreciate you all being here; appreciate the opportunity to hear about this subject. I've been hearing about it for seven long years now. I want to see it move, move, move.

So, with that said, I would defer to our new Renewables Committee Chair, I've been in that position in the past, and give her an opportunity to say a few words.

PRESIDING MEMBER LEVIN: I just want to say good morning and thank you all, especially to the staff, for putting this together. I think this is a very important topic. And having just read large sections of the proposed federal legislation on cap-and-trade and renewables, I think California will continue to lead the way; and where we go is going to be very important for climate change, the state and the country's climate change goals. So, thank you, all.

MS. KOROSEC: All right. With that I'll turn it over to Jason Orta of our staff.

MR. ORTA: Good morning. My name is Jason Orta and I am with the California Energy

Commission's renewable energy program. I am currently the lead for the existing renewable facilities program. We will be talking about that program at this workshop today. And I am also going to be moderating this workshop on biopower.

Before we begin here is an overview of the various policy goals relating to renewable energy in California. As you all know, there is a goal of 20 percent renewable electricity by the year 2010 in California. There's also a 33 percent renewable goal by the year 2020.

Within those goals 20 percent of the 20 percent, and 20 percent of the 33 percent must come from biopower per the Governor's executive order S-0606.

This workshop will focus on the biopower goals in that executive order, even though that executive order calls for biofuels goals, this workshop will emphasize the current status towards meeting the biopower goals along with obstacles and opportunities to meet those goals in 2010 and in 2020.

The 2009 Integrated Energy Policy Report scoping plan -- scoping order outlines a discussion of the following issues relating to biopower in the 2009 IEPR.

This includes a discussion of progress towards meeting 20 percent of the state's renewable portfolio standard targets with biomass; identifying barriers towards that goal, including potential competition for feedstocks between the electricity and transportation sectors; along with reporting on ongoing activities and progress in identifying and securing federal and state funding for research, development and demonstration projects to advance the use of biomass for electricity generation.

So, how does that relate to the workshop that we're having today? There are three goals for this workshop. The first goal is to discuss biopower's current role in meeting California's RPS. The second goal is to discuss the obstacles to meeting the Governor's executive order relating to biopower. And also the potential -- we also plan to discuss the potential for expanded use of biogas. And also we'll have a speaker that will discuss the potential of cofiring solid fuel biomass at coal power plants.

We have a very full agenda today. And judging from discussions that I've had with stakeholders before this workshop, it looks like there's a lot of interest and plenty of -- we expect a lot of comments.

We have a lot of speakers today, but we will have three comment periods after each of the topics.

After my presentation there will be a couple of presentations on existing and potential biopower contributions to the RPS. There will be a comment period after that topic.

And after that we will discuss biogas technologies for electricity generation. This includes landfill gas and dairy digester applications. What are the challenges and opportunities for increasing the recovery of biogas for electricity generation. And there will be a comment period after this topic.

We will also discuss solid fuel biomass feedstocks from landfills and forests. This also includes a discussion of fuel supplies and environmental impacts of solid fuel biomass facilities. There will be a comment period after this section, as well.

And after that will be our presentation from KEMA that will discuss cofiring solid fuel biomass at coal power plants. There will also be a comment period after this presentation, as well.

If you would like to provide comments, there are some blue cards up at the front for you to fill out. Please put your name and the organization that you're with. And please describe briefly what types of comments you'd like to provide.

We will have staff going around the room and collecting those and handing them to me. So staff is collecting them. There's Terrance right over there raising his hand, standing up right now.

And also we will be taking comments online using the functions on WebEx, as well. And staff will let us know any comments that come from there.

Also, be sure to keep your comments brief; and focus on solutions that could be undertaken by the Energy Commission. We want to focus on things that staff can recommend, and that we can eventually do here.

But we're also accepting written comments, as well. And in your written comments I encourage you to submit those; please, you know, go into more detail in those written comments. And please email them to docket@energy.state. ca.us. And don't forget to mention the docket number for this proceeding, which is 09-IEP-1G.

And I will turn it over to our next presenter who will discuss current activities relating to the existing renewable facilities program, and that's Garry O'Neill.

PRESIDING MEMBER BYRON: Mr. Orta, I hope you'll remind us when those comment periods are, because I can't quite tell from the agenda where the breaks are.

MR. ORTA: Okay, I will do that.

PRESIDING MEMBER BYRON: Thank you.

MR. O'NEILL: Good morning. I will be providing a brief overview of the existing renewable facilities program and how they relate to California's RPS and the goals to meeting the Governor's executive order S-0606.

I will be providing kind of a brief overview of the program and a little bit of a background and some of the barriers and solutions the facilities, themselves, have provided to us on their application for funding each year that will kind of tie into this workshop.

Brief background of the existing renewable facilities program is this program provides production-based incentives to existing solid fuel biomass facilities that have been online since before 1996.

These facilities, current eligible technologies are solid fuel biomass, solar thermal and wind. Wind is eligible, but currently doesn't require assistance, so they don't receive funding from us. I'll be focusing on solid fuel biomass because that's what relates to this workshop.

Funding for these facilities is based on a target price that is set to the facilities based on their contract. Each facility, this target price is then compared to what they're actually paid for energy, for their energy price. And the difference is paid on a cent-per-kilowatt-hour basis.

Since 1998 the existing renewable facilities program provided roughly $180 million in incentives to these facilities, to solid fuel biomass facilities.

Just to kind of give you an overview of the participation of the facilities since 1998, you see that it's remained fairly steady. It peaked in 2001 with 30 facilities that participated. Some facilities actually went offline. We've actually lost six facilities since then.

But we've also had some success stories. There was one of those facilities that shut down, was able to restart in 2005 roughly. And then they actually reapplied for funding in 2007 for the first time. That facility no longer received funding from the Energy Commission. They are, as they state on their application, self-sustaining and they don't require public assistance to remain operational.

Two other facilities were actually able to restart in 2008, as well. Those facilities shut down in the early 1990s before the program actually started. And those facilities are now actually operations. And they also receive funding from the Energy Commission.

The role of existing solid fuel biomass facilities in the RPS is pretty significant. Based on IOU claims -- based on claims from the IOUs they make up about 70 to 73 percent of the bioenergy claims based on the RPS verification report.

Fifteen, 16 percent of those claims -- of the total RPS claims come from these facilities, as well. So they do make up a significant portion of the state's RPS.

Some of the barriers that these facilities have basically stated to us in their applications for funding is that fuel costs and fuel availability is a major barrier to remaining self-sustaining and competitive.

Some of the fuel costs that they have stated to us range between $20 to $60 per bone dry ton. This is significant because based on a simple conversion roughly one bone dry ton will generate roughly one megawatt hour of generation. And most of these facilities receive a fixed price contract under PG&E, which averages about $65, $66 per megawatt hour.

So if you're on the high end of that spectrum you're really not making any money, and it's really difficult for you to remain operational, which is why we offer funding to help sustain this industry.

Some of the causes for fuel costs and factors that are decreasing the availability of fuel is right now there is a decline in the timber industry. So any facility that is co-located with a sawmill is seeing a drastic reduction in inexpensive cheap fuel from their sawmills. So they're having to truck in fuel from farther and farther away.

There's also a decline in the construction and the deconstruction industry. There just isn't any construction -- or very little construction going on right now. So the waste stream from there is also diminished.

And based on these two points any facility that requires those two sources of feedstock to remain operational, they have to truck in fuel from farther and farther away.

And fuel prices within the last few years have increased and increased; it spiked in 2007. And it has declined a little bit in 2008, but it's still much higher than it was before. And fuel diesel prices are one of the major factors contributing to the high cost of fuel.

There's also an increased amount of competition for feedstocks. Some of the examples of competition for these feedstocks would be the -- sorry, one moment, got a complete list -- we've got chicken farmers and landscape and tree clearing used for compost. And then mulch and then landfill waste is used for alternative daily cover at landfills.

There are other barriers that these facilities have stated on their applications, but I'm focusing on these because these actually meet the scope of this workshop.

So, financial concerns and greenhouse gas offset concerns aren't really part of the scope of this workshop, so I'm kind of leaving them out.

These are a list of some of the solutions --

ASSOCIATE MEMBER BOYD: Excuse me, can I rudely interrupt?

MR. O'NEILL: Yes.

ASSOCIATE MEMBER BOYD: To me missing from the chart on costs and availability barriers is the issue of access to fuel. And I know others in the audience will likely bring this up. But I just want the audience to recognize that the Commission recognizes that as an issue.

And by that I mean there are some fuels, or in the timber arena, that are off limits to us at the present time based on certain federal rules and regulations, et cetera, et cetera, which we've identified for a long time as an issue that needs to be resolved. And it is constantly being discussed. And it may or may not get resolved in the not-too-distant future. But I think we should acknowledge that that is a problem that we face in this state. Enough said.

MR. ORTA: Commissioner Boyd, in the afternoon on our agenda we have scheduled speakers from the California Department of Forestry and the U.S. Forest Service that will assist in answering questions that the public may have about those regulations.

ASSOCIATE MEMBER BOYD: Thank you. And I knew they were on the agenda, and I know there's people I know in the audience who will bring it up. But I just wanted the audience to recognize that we recognize, we, the Energy Commission, recognize it's a problem.

I failed to mention in the beginning today that I've been chairing the Governor's Bioenergy Interagency Working Group for the duration of this Governor, and chaired the equivalent organization for a good part of the last governor.

And it's like pushing a rock uphill that I fear constantly is going to roll back over me and the rest of us. But, you know, we are making progress. This is just another barrier to access to a fuel source that we're working on. And I think, soon, we'll, in the not-too-distant future, on my last working term, which is right now, we'll get it solved.

MR. O'NEILL: Okay. And just to clarify, this isn't a complete list of the barriers that these fuel facilities are facing. And I hope I'm not giving that impression.

These are just the barriers that were contained in their funding applications. So it's a good point to raise.

ASSOCIATE MEMBER BOYD: Thank you. I never miss a chance on soapbox --

(Laughter.)

MR. O'NEILL: So this is a list of the industry-proposed solutions to overcoming some of these obstacles. These are not the only solutions that are in place by the industry, but these are just some of the solutions that they have put forth and they are actively pursuing.

I've broken them out into two sections.

One is statutory/regulatory changes. There's a list of some things that would help access more fuel if these regulations were put into place.

Examples are restricting open burning of agricultural waste. This would allow facilities -- this would actually serve two functions. It would increase the availability of fuel, but it would also entice farmers or agricultural industry to help offset some of the cost of fuel for transportation. Because they would need to actually get rid of this waste, so they would be enticed in helping out split some of that cost.

Diverting more waste from the landfills. Limit the use of alternative daily cover. Facilities have repeatedly stated in their application that there is a lot of, what they see as a lot of very valuable fuel that is being used to cover the landfill on a daily basis.

This green waste, they feel if it was diverted from the landfill to their facilities could help drop the cost of fuel. Also, this is fuel that's already been collected, so it's in a central location. So there would not be that -- it would actually be a lot less expensive to actually transport.

Some of the facilities are working with county agencies to try to access some of the slash from logging operations. Currently there's fuel piles that are just burned after these logging operations because it's not cost effective to transport these fuels out of the forest.

We also are working -- they were also working on removing the ban on federal forest-derived fuel; that was actually contained within a statute that was passed last year, SB-3048.

Other solutions. These are industry-based solutions that the facilities are actively pursuing. One of the facilities are looking at creating fuel yards, kind of centrally located, to collect fuel. This would reduce the cost of gathering and transporting the fuel because it would all be centrally located.

Improving fuel-processing systems in a variety of ways. An example of that would be covering the fuel pile so that when it rains it wouldn't get moisture. This is going to decrease the moisture content, and therefore increase the efficiency of burning that fuel.

And then other plant efficiency improvements that would increase the value of the fuel as they're burning it, so increase the amount of megawatt hours that they were getting out of that fuel as they burn it.

And then this is just a list of some additional links and some documents that are referenced in this presentation if you're interested. The verification report won't be published -- or it's expected to be published sometime this summer. So that information may change, but that's where you can find that information that was supplied earlier.

And with that I will --

MR. ORTA: Thank you, Garry. Our next speaker will talk about the progress not just from the fleet of existing renewable facilities that participate in that program, but also the entire progress, the progress of the entire biopower fleet in meeting the Governor's executive order. And a discussion of current trends in meeting that order, that executive order, in the future.

Kevin Barker from the Energy Commission's renewable energy program will speak on those points.

MR. BARKER: Good morning. As Jason said, I'm Kevin Barker. Excuse me, I have a bit of a hoarse voice right now, so bear with me.

Going to be talking about California's existing biopower and progress toward reaching the bioenergy executive order, S-0606.

As you can see in the bottom right-hand corner, looks like a sand dune, but I assure you that is biomass. It's actually rice hulls. One of the existing biomass facilities functions by burning rice hulls.

The biopower portion is linked with the renewable portfolio standard and it has two important dates, 2010 and 2020. And it calls for 20 percent of the renewable portfolio standard to be met by bioenergy in 2010 and 2020.

RPS was signed into law in 2002. And assigned roles to the Energy Commission, the CPUC, and requires retail sellers to procure 20 percent renewable energy by 2010.

Publicly owned utilities set their own RPS goals, recognizing the intent of the Legislature to attain a target of 20 percent of California retail sales of electricity from renewable energy by 2010.

Most recently, signed in November 2008, is the Governor's executive order S-1408, which sets a further goal of 33 percent renewable energy by 2020, and streamlines California's renewable energy project approval process.

Please note that the RPS procurement compliance is measured in terms of electricity delivered and not solely signed contracts.

This next graph shows the goal of 33 percent by 2020 and the goal of 20 percent by 2010. We have a range of electricity needed for the 2020 goal. The top range is roughly over 100,000 gigawatt hours. And the bottom range takes into account the ARB's AB-32 scoping plan for energy efficiency, CHP, combined heat and power, and also includes the CSI goals, the California Solar Initiative goals. And this would reduce the electricity needed to around 78,000 gigawatt hours.

Also a couple other notes. You can see here that we are at around 11 percent when the RPS began. And as of 2007 we were roughly at around 11.8 percent renewables.

Here are some eligible biopower technologies. Biodiesel. Biomass, and in biomass that could mean the convention idea of solid fuel combustion. It could also mean gasification of biomass. There's digester gas, which can be thought of as wastewater treatment or at the dairies.

Fuel cells using bioenergy. Landfill gas. And limited municipal solid waste. There is a technology that is available for the renewable portfolio standard, and it requires that no oxygen be used at any point during the process.

Please note that there is also one municipal solid waste facility that is available in Stanislaus County -- that is eligible in Stanislaus County, that uses combustion.

Some combination of technologies are cofiring biomass with coal. We are going to have a speaker talk about that later on in the day. And some solar thermal electric facilities, which, instead of cofiring with natural gas, they use biogas.

And there are some -- they use, excuse me, biogas or solid fuel biomass -- and there are some facilities that have signed contracts currently for this technology.

PRESIDING MEMBER BYRON: Kevin.

MR. BARKER: Yes.

PRESIDING MEMBER BYRON: While you're

doing definitions here, there's been several references in the presentation to cofiring biomass with coal, which is more of a concern to states other than California.

But one of the interests we had in using any and all of our waste stream in California, and there is a substantial amount of petroleum coke in California that is part of the waste stream, and it's similar to coal. Would cofiring biomass with petroleum coke be eligible?

MR. BARKER: As a multifuel technology, it would be available. However, there is a de minimis in which they would only count the biomass portion towards the RPS.

MS. BROWN: Can you also explain what you mean by MSW limited in your prior slide?

MR. BARKER: There is one facility, one MSW facility that does use combustion. And they are eligible for the RPS. They're located in Stanislaus County.

And there is a technology that the RPS does, I guess, give an outline as to how it can be met, and I don't know the specifics, but I do know that it says that no oxygen can be used at any point during the process.

And I don't know if someone in our RPS unit is here that could clarify further, but --

MS. BROWN: I suspect other speakers will address the infamous conversion technology definition. I think --

MR. BARKER: Correct, yes.

MS. BROWN: -- that's probably what you're getting at, right?

MR. BARKER: Correct.

MS. BROWN: All right, thanks.

ASSOCIATE MEMBER BOYD: That was a setup, but you didn't see it coming.

(Laughter.)

MR. BARKER: This slide shows the bioenergy portion of the RPS as of 2006. This is existing bioenergy from the RPS. And this slide includes the IOUs and ESP procured RPS energy. Just note this is unverified claims.

And if we do include the publicly owned utilities, the orange slice would be 20 percent. In a couple other slides -- in the future slides I will show a percentage of past and going into the future. But this just shows that a large portion is made up of what's called biomass.

MS. BROWN: So, just to be clear, what

you're saying is if the public utilities are counted in the equation then we're meeting our biopower goals today?

MR. BARKER: That is correct.

And we do have a fairly significant portion of landfill gas, as well, almost 25 percent. And the rest is made up of digester gas and MSW combustion.

Okay, this is the slide I was talking about. This is percent of renewables from bioenergy. This goes back to 1983. And this is of all renewables, this isn't just of RPS. But as you can see, at some points, looks like around '91 or so, we were almost up to 25 percent biomass of our renewable portion. And it stayed steady from around 2005, 2004, at around 20 percent.

Just a note, the dark line is existing organic waste generation. The red line is contracted organic waste. And that is contracted either with the investor-owned utilities or publicly owned utilities. And the renewable energy staff has developed a bioenergy scenario to meet the Governor's order of 20 percent by 2020. And that is seen in the dotted line.

So as this graph shows, if we are just

taking contracted biomass, we are not going to meet the 2010 goal that the Governor has set for it.

This next slide shows the previous slide's percentages, but in terms of generation. We are slowly building up, even though there was a large dip after 2008 to 2012 in the previous slide. We are steadily growing with generation, however our load is also increasing.

The red portion shows -- actually, let me jump back, sorry, go ahead. Okay. Let me drop back.

As you can see, if we do just continue with the contracted bioenergy we will drop to roughly around 11 percent. So there is definitely a significance as to trying to get more bioenergy.

Okay, so this next slide shows where we need to be, and it's roughly around 15,500 gigawatt hours by 2020 in order to meet the Governor's executive order.

And just note this is looking at the low end of the range, the previous range that were shown. So that's also with the AB-32 energy efficiency, CHP and CSI goals, if they were met. We would need roughly around 15,500 gigawatt hours.

These are contracted investor-owned utilities-signed RPS contracts by technology. And just quickly, just to note, if you do look at the right-hand column, that is total projected deliveries. And biomass with biogas makes up less than 10 percent of the projected deliveries. So that does show the reason why there is that decline from around 20 percent to it was around, I think, 15 percent by 2012.

PRESIDING MEMBER LEVIN: So this is projected deliveries in 2012, because there's no -- I don't see a date on it.

MR. BARKER: The date, some of the projections go out further than 2012. It's just whenever the signed contract, the expected deliveries of the sign contract.

This is another slide showing the similar results of the last one. And as you can see, the biogas is a very very small sliver. You can see that there is a little bit green, which is showing that they are on track and they are online.

The biomass portion, it's kind of hard to see, but there are some delayed, quite a good portion that are delayed and not online. And then a small sliver that are on track, but not online yet, at the top.

And then there's roughly around a third that have been cancelled. And these are, let's see, these are contract status for new, repower and restart capacity from contracts signed since 2002 in the investor-owned utilities database.

PRESIDING MEMBER BYRON: Mr. Barker, could you clarify again a third of what contracts have been cancelled?

MR. BARKER: A third of either new, repowered or restart contracts that have been signed since the RPS in 2002. Excuse me, biomass.

PRESIDING MEMBER BYRON: Do we know why?

MR. BARKER: I don't --

MR. ORTA: Well, a few years ago we hired a contractor, we hired KEMA to prepare a study on RPS contract failure. And some of the findings were basically difficulties getting financing; transmission constraints.

In that study that one-third number was in there, up to one-third of these contracts could fail based on those constraints and others.

PRESIDING MEMBER BYRON: Yes, thank you

for reminding me. I do recall that study. Thank you.

MR. BARKER: Okay, this next slide is showing projections for bioenergy executive order S-0606. This is the RPS portion of the goal.

And I do want to point out the two green highlighted years which are the executive order calls for 2010 and 2020. Roughly around 11,000 gigawatt hours would be needed in order to meet the 2010 executive order. That calls for roughly around 9.3 million bone dry tons of either biomass or biogas.

In 2020 we would need to jump that or escalate that to the 15,500 or 15,600 gigawatt hours. And that would make up roughly around 12.5 million bone dry tons.

Do note that the last column shows technical available biomass in California. And that is around 40.4 million bone dry tons per year.

If the renewable -- if the biomass portion were to be extended past 2020 to the 2050 goal that the bioenergy portion, the transportation side portion, has, we would need roughly around 34,000 gigawatt hours of biomass, which equates to about 27 million bone dry tons.

This slide shows -- the bottom table shows the transportation side with the biomass needed. You can note that in 2020 the 12.5 million bone dry tons are needed in order to meet the biopower portion of the S-0606. And in order to meet the bioenergy or the transportation portion of the goal, they would need around 11.4 million bone dry tons, which comes out to roughly around 24 million bone dry tons.

And as of right now, or what is projected, there would be enough technical potential to meet that.

About 15,000 -- as I said before, about 15,500 gigawatt hours of bioenergy would be needed. However, to meet both of the goals around 24 million bone dry tons of feedstock is needed. The amount needed is likely to exceed instate biomass or biogas for 2050. Out-of-state biomass and biogas can be used for the RPS portion of this goal.

So, by 2050, if we go to the right column of the bottom table, if we add the transportation and the RPS portion of the goal, then we come up to almost 70 million bone dry tons, which far exceeds the technical potential of 40 million per year.

This slide shows the biomass distributed PV 33 percent scenario resource mix. This was developed by the renewable energy office. We used portions of the Public Utilities constrained transportation case, and information that was presented in the renewable energy transmission initiative phase 1B report.

As was noted before, we needed to add -- we needed a total of about 15,500 gigawatt hours of biomass. In a future slide I will show how much we currently have of biomass and how much we need. This scenario included around 9000 additional gigawatt hours of biomass.

We also added a large portion of distributed solar generation, a little over 8000 megawatts of distributed solar. This is consistent with the Public Utilities Commission's renewables, their transmission-constrained case, which they added almost 9000 gigawatt -- or almost 9000 megawatts of distributed solar.

PRESIDING MEMBER LEVIN: Mr. Barker, --

MR. BARKER: Yes.

PRESIDING MEMBER LEVIN: -- I'm sorry,

I'm still stuck on the previous slide.

MR. BARKER: Yes.

PRESIDING MEMBER LEVIN: There's a huge amount of information in this slide, and I'm struggling to figure out, there are only asterisks saying there could be a different number if AB-32 goals are met.

Why is that only in some places? You know, for instance, why is it under biomass/ biogas, but not transportation? And I guess even maybe more importantly, why aren't we assuming AB-32 goals will be met, and make that the basecase, since it's state law?

MR. BARKER: This scenario does assume that AB-32 goals are met. Sorry, I should have gone into that. The adjusted California retail sales, which is the top -- if you look at the top table, the top left row, adjusted California retail sales of 33 percent. That's looking at 2020. That does assume that the AB-32 goals for energy efficiency, combined heat and power and also the California Solar Initiative are met.

So the retail sales, if all that is met, would be almost 240,000 gigawatt hours.

PRESIDING MEMBER LEVIN: So the entire

top graph assumes AB-32 goals are met?

MR. BARKER: That's correct.

PRESIDING MEMBER LEVIN: Okay. And in the lower graph, it looks like it doesn't assume that, and only caveats that in two of the four categories --

MR. BARKER: We didn't --

PRESIDING MEMBER LEVIN: Can you explain that?

MR. BARKER: We didn't look at the transportation side. We took what was developed by the transportation sector in the Energy Commission. We were just looking at the renewable portfolio portion.

PRESIDING MEMBER LEVIN: Okay, thank you.

PRESIDING MEMBER BYRON: Good question.

MR. BARKER: Thanks for clarifying that.

PRESIDING MEMBER LEVIN: I didn't, you did.

(Laughter.)

MR. BARKER: Okay.

MR. ORTA: Excuse me, Kevin. There was a question on WebEx. It asks if you can define what technical potential is.

MR. BARKER: Technical potential, I guess, would be how much actual biomass feedstock is out there. It doesn't take into account if it's economically feasible, if we can get to it, if there are laws that allow us to get to it.

So technical is the larger slice.

Economic potential would be the smaller slice.

PRESIDING MEMBER LEVIN: And actually I had a similar question. So technical potential just means there's enough feedstock available, not necessarily facilities, or both?

MR. BARKER: It means that there's feedstock out there somewhere in California. Whether we can get to it or not would be looking more at the economic potential.

So, there is roughly around -- or by 2020 and 2050 there would be roughly around 40 million bone dry tons of feedstock out there. Whether we can get to it or not is yet to be seen.

PRESIDING MEMBER LEVIN: Well, putting aside the economics, but does that also assume that we currently have or will have existing sufficient facilities for it? Or it's really just about the availability of feedstock?

MR. BARKER: It's just feedstock.

PRESIDING MEMBER LEVIN: Okay.

ASSOCIATE MEMBER BOYD: I might supplement and say the Energy Commission, through research contracts and through our sponsorship of the Biomass Collaborative at UC Davis and other facilities and faculties, has produced reports in the past about how much biomass is there out there.

And then comes down to how much, you know, -- for what fraction of that is there deemed technical feasibility to get at it. We lack the facilities to utilize it, but the technical feasibility to get it.

And then there's the number that's been referenced here, what we're using today. So this is knowledge we've had for a long time, we've just -- and there's a lot of reasons, predominately, well, a major one is economics. But there the other reasons we're hearing today why we haven't pushed into that frontier just yet. We hope to.

MR. BARKER: So as I was -- this slide was showing our scenario. We did add quite a bit of distributed solar. I wanted to note that the distributed solar here, the 8102 megawatts, is not strictly rule 21 compliant. This was relaxed a little bit and that the PV cannot be more than 30 percent of peak load on the feeder, rather than 15 percent.

This was in order to reflect that fact that solar resources do not produce at night during lowest load hours.

The biomass, the top five rows were taken from the RETI phase 1B report. We looked at counties that were in attainment for, federal attainment, for particulate matter less than 2.5, another category less than 10. And eight-hour ozone. And we selected the biomass to be placed into those counties.

Then there are the bottom two -- or not bottom two, the two below that is the actual biomass and biogas that we were showing before that have actually been contracted, that have RPS signed contracts.

This is a recap of the scenario. We needed roughly around 77,950 gigawatt hours of renewables. Thirty-three percent of an adjusted statewide retail sales from the demand forecast, which includes the million solar roofs, or the California Solar Initiative, AB-32's scoping plans for energy efficiency and combined heat and power.

The calculation of additional renewables needed is of the 77,950 gigawatt hours, minus what we currently have, which is roughly around 32,400 -- well, not roughly, exactly 32,469 gigawatt hours, and that includes imports, equals an additional 45,500-or-so gigawatt hours of renewables needed by 2020.

The renewables buildout for 2012. So from the existing fleet of 2008 to 2012 was based on projects from the Energy Commission's investor-owned utility and publicly owned utility contract database. Plus some geothermal from the Renewable Energy Transmission Initiative phase 1B Imperial North CREZ. CREZ stands for competitive renewable energy zone.

As I said before, the biomass projects chosen from the RETI Phase 1B were in federal attainment counties for particulate matter 2.5, 10 and ozone eight-hour. We also took the lowest cost projects first.

The distributed level PV from RETI Phase 1B was selected in counties with the highest population densities.

And here are some maps of where the

projects were selected. This does not include the investor-owned utility and publicly owned utility contracts. These maps right now just include the biomass and PV that was added. We are looking to update these maps in order to include the signed contracts, as well.

So, as you can see, the large portion of the biomass is going to be met through northern California. This is a map of central California in which a good portion of the distributed solar. Let me also clarify, each dot of this distributed solar equates to about a 20 megawatt plant.

The red dots are the PV, the photovoltaics. The blue at the top part, not blue, the purple squares are for biomass. And very small is the size of the plants. And RETI identified the size of these plants. So it's really hard to read, but hopefully on the slides you can. The top left corner would be biomass plant of 22 megawatts.

This slide shows southern California. There are two counties in southern California that have met the federal attainment for all three of the -- the two particulate matters and the eight-hour ozone. There are two biomass plants in these counties; and the rest is made up with distributed solar.

There is some out-of-state biomass that RETI has identified. We took the lowest cost of these. There's two plants in Washington and two in Oregon.

As a note, the executive order does not require that the RPS portion is met with instate bioenergy -- biopower. So there is an option of looking to out-of-state resources in order to meet this goal.

And the last one is thanks to the Energy Commission Staff that helped put this presentation together, Pam Doughman, Madelaine Meade, Jacque Gilbreath, Jason Orta and Garry O'Neill and other staff. Any information, please direct them to myself, Kevin Barker. My email address is kbarker@energy.state.ca.us. You can also reach me by phone at 916-651-6176.

PRESIDING MEMBER LEVIN: Kevin, I'd like to thank you and the other staff, and offer my apologies to all of you. Unfortunately, I've been triple booked for virtually the entire day. So I have to depart now. I'm leaving this in very able hands. But, thank you, all, again; it's been very helpful.

MR. ORTA: Our next speaker is Steve Kaffka from UC Davis. Steve also works on the California Biomass Collaborative, which is a group that we have -- we, the Energy Commission, have helped funded that consists of industry, academia and government -- and representatives from various government agencies.

Steve's presentation is going to go a little bit more into feedstock potential to meet our biopower goals.

And after Steve's presentation will be the first comment period of the workshop.

DR. KAFFKA: Good morning, and thank you for inviting me. There are a large number of names here on this first slide. I'd like to say that in particular the majority of the work was done, that I'll be reporting on, by Quinn Hart, Nathan Parker and Peter Tittman. I've had help here from Rob Williams and Bryan Jenkins. In fact, ideal world, Bryan Jenkins would make this presentation, but unfortunately, he couldn't be here today.

California Biomass Collaborative has a website listed here on this slide. And the

Collaborative does a number of things. We provide statewide biomass -- we have a statewide biomass coordinating group. We have a facilities reporting system. We have biomass resource assessments and reports, and assessments that you can find on the website.

And everything that I'll talk about here is either from the biomass roadmap for development of bioenergy in California, or from the report that's been recently posted on the website that Peter Tittman and Nathan Parker and Bryan Jenkins have produced.

I was asked to provide a technical overview of potential biopower technologies, as well as address the issue of competition for feedstocks between the biopower and biofuel industries. And that's a very real issue.

I'll try to actually frame a little bit about the biopower technology. You've seen some of that already, so I'll go through that relatively quickly.

And then talk about the modeling study I'll be reporting on here which tries to assess using optimization and GIS methods, the potential for that competition.

This is from the roadmap and from the biomass website, and it addresses the potential feedstock and the gross biomass or the technically available and technically recoverable feedstock. These numbers are roughly around 35- to a little less than 40 million bone dry tons from previous assessments.

The Collaborative is constantly working on this. We have a number of current projects and future ones contracted to improve these estimates of the resources available and the technical availability of those resources.

We'll be talking about -- there's a number of biomass conversion pathways. Today we're going to be particularly talking about thermal -- conversion, energy, heat and electricity, as well as bioconversion to liquids and gases that might be used for transportation as well as biopower.

But there are a large number of other technologies that are affected that are essentially biomass or biopower technologies.

This is a little bit out of date. You heard an earlier -- this is a total potential, bioenergy potentials by categories, particularly from lignocellulosic sources. Again, from the roadmap. And it gives you an idea basically this is what might be, we think, at least in the first cut, reasonably available. Not going to dwell on these numbers. You can look at them on the handout.

And this was a scenario created by Dr. Jenkins at one point in time, not accounting for the actual potential economic cost associated with recovery of biomass energy, but at least one scenario about a potential future technology.

In fact, it included quite a substantial increase in biofuels, particularly from agricultural purpose-grown energy crops. This was in the pre low carbon fuel standard day, and it may not be possible to produce biofuels from agricultural feedstocks under the low carbon fuel standard, if it's adopted as it's currently proposed.

So basically we don't use nearly anything like the potential or technically recoverable biomass in California. This is from a roughly 2006 estimate. I don't think it's changed too much. I think it's hard to actually compare presentations here to do all the numbers and calculations in your head as you go through these.

But basically we're only using currently effectively a portion of the biomass that's available.

And as has been reported, we have to substantially increase, if we're going to meet the Governor's goal, the capacity to generate electricity from biomass over time. And it's not clear that we may be able to meet all those goals. It depends on a lot of things that haven't actually happened yet.

Now one of the important things to consider about the biomass power industry is that it operates, for the most part, using technology that's about 20 percent efficient. So conversion of electricity to biomass operates more or less in the area where we see circles.

And the installed capacity and the cost of electricity production. This is, again, from about 2006. There's some of the assumptions associated with making this calculation.

You can see that there's a potential to increase the efficiency of biomass power generation -- power generation from biomass. It would be possible to go from 20 to 30 percent under certain economic scenarios.

The next 10 percent increase would be less likely in terms of the returns over the costs of improving the technology. But there still is some room for improvements in power conversion. And that will have a big influence, or could have a big influence on the competitiveness of electricity generation from biomass versus biofuels.

And basically another thing that would improve the economic competitiveness of electricity production from biomass is the recovery of waste heat from that process, the combined heat and power process.

As you move from current nonrecovery conditions through finding an increased value for the heat of recovery, the cost of generation, the cost of electricity generation declines. It's not, however, an easy thing to find a use for that waste heat at existing facilities.

So what I want to report on primarily is results from this first phase of a study on the economic potential of California biomass resources for energy and for biofuel. This is the work of some smart grad students, Peter Tittman and Nathan

Parker, Quinn Hart, Bryan Jenkins and Muy Lai.

What about -- it's important when you talk about modeling that you at least have some idea of some of the assumptions or underlying conditions for the results that you talk about.

So, economically available biomass in this case depends on the value of the products that can be made from the biomass, the cost and efficiency of conversion to those products, and engineering and economics of the acquisition of the biomass. Those are all modeled, or values are given for them in the study. Which is, as I said, I mentioned it's available on the website.

There's some limitations. A lot of what we have to try to model isn't really as well known, or certainly not as well developed as we would like at this stage. It's a work in progress, very much so, the biomass industry.

So, the status and development of certain technologies is uncertain. There's a reliance on biomass resource assessments that, in some cases, are incomplete, that don't include their own economic modeling for in terms of resource accessibility.

And there isn't really a feedback in the model between the potential siting of plants in biomass and the resource costs.

Basically the model does these engineering and economic models of biorefineries. It uses spatially explicit resource assessment, meaning in other words, it tries to link GIS-based location of biomass and transportation and cost models with the availability of biomass with locations of refineries through a supply chain to predict availability and location.

There are certain other model limitations. As I said, the status and development of these technologies is uncertain, and so on. It relies heavily on biomass -- I'm going the wrong way, sorry. You've already seen that.

So what does the model try to do? It tries to maximize total industry annualized profit. It's a mixed linear -- mixed -- linear programming model. It's an optimization model, as I mentioned. It locates and sizes biorefineries based on the distribution of biomass resources. It chooses which technology to use. And it allocates resource and demand to each biorefinery.

This is basically just a schematic of

how that goes. You have price levels that can be modeled, different price levels for different biomass types that can be fed through different biomass supply points, into potential biorefinery sites through fuel distribution. And then in this case, to electricity substations.

These are some of the more -- the majority of the resources that are modeled currently. More can be added in the future, and may. Corn stover and corn play a large role in this modeling. This modeling was part of a project that also included not just California, but the Western Governors Association region, which is west of the Mississippi. So corn is an important feature in the model.

It involves forest thinnings, animal fats and waste greases, MSW and woody residues. And this gives you both the types of materials and the geographical scale at which they will be available. Some of the data sources.

This is the relative feedstock conversion pathways that are modeled. You have various kinds of virgin lignocellulosic materials like orchard and vineyard wastes and so on. Biomass energy crops; forest biomass and so on.

You have corn there. You have fatty acids from seed oils and so on. And then lignocellulosic fractions of MSW. And they can go through various types of conversion technologies to various types of energy.

So the biorefineries are also assumed to operate at design capacity. The cost curves are fitted to match these economies of scale from the detailed models of conversion costs. Cost functions depend on either feedstock input or fuel product or both. And the biorefineries are modeled to assume a constant mix of feedstocks over the entire period. Not all of those obviously would be true in real life, especially, for instance, constant feedstock types and supply.

Now, geography's important. This little graph gives you an idea of the costs of distance versus the cost of transportation. You have a 35-mile-per-hour diesel truck, 65 mile-per-hour diesel truck, rail and marine. Marine obviously is always cheaper. If you can float it, it's by far the cheapest way to do things. But in the dry west we can't use barges as much as we might like.

This is again from the larger Western Governors Association, just emphasizing the

California portion. And it gives various estimates of lignocellulosic residues by region. We're going to just concentrate on the California portion.

There's more to read here than you can do. And I don't put it up to try to go over any of these numbers in detail. You can take a look at this chart on the handout, and also on the website.

The point I want to make with this is that technology is predicted and expected in the model to change over time with increasing efficiency and lower overall costs per unit.

So with respect to time series predictions in the model, there are expected to be changes and improvements in efficiency.

But all these potential changes are still estimated, because, in fact, they haven't happened yet and it's very difficult to know exactly what form those changes will take. So these represent the best judgments of the modelers.

Now, one of the things that comes out of the work is that there's a tradeoff between the size of the biorefinery, or in fact, the power plant, and the cost.

So, as a refinery or power plant increases in size it's conversion efficiency, the cost of conversion drops. But the cost of assembling feedstock from larger and larger areas increase. And so the combined combination of that ends up having more or less an optimum size by location, depending on the biorefinery or type of plant that's being used, and its geographical location.

So, let's talk about some results. This is one of the maps from the report that talks about the distribution of biomass wastes and the approximate amounts. There's again, quite a few numbers on here, and it's not so important.

Quite obviously the forest biomass resources are along the coast and in the Sierra Nevada, while the agricultural residues and MSW are close to cities or in the great central valley where there's a great deal of biomass, agricultural biomass generated.

This is a prediction of biomass procurement costs versus biomass available as a supply. And you can see, basically, that there's a great deal of emphasis on MSW; a much smaller emphasis on tallow and things like straw and stover. And forest resources are the issues -- or the materials that dominate, as does corn. Again, this is assuming that corn's both produced and imported into California.

Now, this is the generic output, or type of supply curve that has been -- that combines all the various sources of biofuels available. So this is for biofuels, the marginal cost of biofuels in terms of dollars per gallon gasoline equivalent.

At around $2.50 the quantity of biofuels essentially reaches something close to the technical limit. It increases at a little bit over $1 a gallon gasoline equivalent. And more or less is steady around the $2 to $2.25 a gallon gasoline equivalent. And then at about $2.50, especially by $3 a gallon gasoline equivalent there's a substantial diversion of biomass to biofuels based on the optimization assumptions in this model.

These are more specific. You can see here curves for more specific sources of biomass. And these curves flatten off when they reach their technical limit of recovery for each of them that is estimated in the model.

And you can see here, under the assumptions that are built into the modeling capacity that corn for ethanol has a substantial role as a source of biomass consumed at prices around $2.50 a gallon.

MSW comes in at a much earlier phase and reaches its limit at around $4 a gallon. This is conversion, again, to biofuels, but not to electricity. This is background before we get to the actual competition with power, biopower.

PRESIDING MEMBER BYRON: Dr. Kaffka, could you go back for just a moment?

DR. KAFFKA: Yeah.

PRESIDING MEMBER BYRON: It's a little difficult to --

DR. KAFFKA: This is a little -- I know it's a hard figure to --

PRESIDING MEMBER BYRON: -- call out the different colors. Can you -- going from right to left, for instance, could you just help us out there?

DR. KAFFKA: Okay. So, the purple is orchard and vineyard waste. The green at the bottom is tallow, so that would be -- and grease.

So tallow and grease, that would be people going around and collecting fats from McDonald's restaurants. And tallow would be from slaughterhouses. And that's being converted right now into biofuels, pretty much thoroughly in the state, as far as we can tell.

Then you have orchard and vineyard wastes. Then you have agricultural residues. That would be corn, stover and straw.

PRESIDING MEMBER BYRON: I'm sorry, what I'm really after is -- I'm having trouble distinguishing, for instance, a couple of the blues and the black here --

DR. KAFFKA: Okay.

PRESIDING MEMBER BYRON: -- for instance. And --

DR. KAFFKA: Well, the black all the way to the right is corn --

PRESIDING MEMBER BYRON: Okay.

DR. KAFFKA: And then the next one over is herbaceous energy crops. That would be things like switchgrass. Perhaps miscanthus or crops perhaps like sweet sorghum or perhaps other types of crops. Perhaps sugar beets.

You have soy and canola there. That's

all the way over on the left. That's a version of vegetable oil.

So basically as the price of, if you will, the biofuel increases, these resources are brought into biofuel production up to the limit of their availability within the region, estimated availability within the region.

And that availability is based not just on simply whether they could be grown, but whether it's efficient to link the production and transport and use of those materials to the infrastructure that's posited in the model.

So, the statewide supply in California is going to be very sensitive to the development of low-cost cellulosic ethanol technology or a technology with similar performance to the LCE technologies model.

In other words, we don't yet have a technology to cheaply and efficiently convert cellulosic materials into ethanol, and the model is sensitive to the assumptions about what those prices will be.

It's also sensitive to demand for biomass for the production of electricity in a way that we'll talk about in a minute. And it's available -- the availability of low-cost cellulosic feedstocks from natural forest is a very critical feature of the outcome of the model, assuming that those resources are available.

Now, this is just focusing on ligno-cellulosic biomass; this is the biomass consumed versus the biofuel price. It's pretty much the same. At the lower end you can see where current biopower systems are modeled or predicted to be competitive and efficient.

But as the price for biofuels rises, should we have another large spike in the price of oil, which would have an effect on making biofuels more valuable, then the potential competitiveness of biopower facilities, as they currently exist, against the biofuel conversion tends to maybe limit it. And that includes also for forestry wastes.

Again, remember, we're assuming we can convert forestry wastes into ethanol in an efficient way.

So, here the slide. Now, on the lower left here is the current status quo, the estimate of the model for the supply of baseline electricity from biomass at biofuel prices. And, again, production levels. Or at power production levels for the electricity scenarios at the top.

And you can see that the prediction is that the current biopower facilities will not be very competitive.

If you add combined heat and power, making the cost of electricity -- if you find a use for that heat, then, in fact, the use of biomass for power becomes much more competitive, up to a certain, again, that magic $2.50 price.

But as you raise that price, and especially if you combine biofuel production with its own combined heat and power, recovery in a modern biorefinery, then at that price the biofuel system is predicted to out-compete electricity.

Now, if you have a 20 percent renewable portfolio standard mandate for electricity from biomass, here, again, you have the supply without the mandate. But with the mandate you're going to have to be in roughly this area of megawatt capacity. And that will be irrespective of price because it's a mandate.

This is the potential use of biofuels, the baseline biofuels facing electricity under the RPS mandate. So, in other words, it makes biofuels much less competitive when you have a mandate for electricity from biomass. It makes biofuels much less competitive under that scenario.

I put this in just to finish up. This is again for the Western Governors Association for the whole area. There's quite a dependence in most of the western states on agricultural biomass for biofuels. Less so in California.

So, this is without crops. The quantity of biofuels available in the Western Governors region is significantly reduced. With crops you have the baseline production, which is substantially larger.

MS. BROWN: Steve, a question.

DR. KAFFKA: Yes.

MS. BROWN: So what you're saying is that for California the waste-based biomass is a larger portion of the potential --

DR. KAFFKA: In this exercise it's --

MS. BROWN: -- when compared to other western states?

DR. KAFFKA: -- predicted. That's correct. That's correct. And forest resources, as well. A lot of the western states are prairie states; they don't have forest resources.

But I wanted to end with a couple of slides about what the future might hold, and things are not really well modeled currently in the modeling scenario that I just presented.

And that is the potential for innovative biorefineries for the generation of various kinds, not just simply biofuels, but all kinds of other products. They could be chemical feedstocks that could be the primary product. They could be high alcohols, higher alcohols; could be ethanol. They could be bio -- oil byproducts. Waste heat and power converted.

As they very modern and efficient biorefineries are proposed and developed, it may shift the relatively competitiveness of the biofuel business versus the biopower business. Especially the current biopower business in California, which was developed largely in the late '80s and early '90s.

And just to show you what, depending on how policies occur, this is a biogas-to-electricity facility in Germany that I visited a little while ago. They're making biogas out of a combination of agricultural products and residues.

They have a very high -- as you may know, those of you that follow this, very high feed-in tariff costs for electricity. So essentially it draws these resources into electricity production.

This is a very efficient system, actually. It really does a great job of fermenting and producing gas and electricity. This could be one of the future outcomes. But, you know, it depends on policy choices that the state faces in the development of technologies, alternative technologies.

So, in summary, with current prices and with current technology there's a limited potential for biofuel production from biomass resources in the western U.S. But as prices rise, that'll change.

More than two-thirds of the potential for biomass energy in the western region requires production of energy crops. But this is not necessarily true for California under the conditions we've modeled and the assumptions that are used so far.

Remember if you can convert woody biomass efficiently at a low enough cost to ethanol, then that California would tend to favor those types of materials. Especially with the low carbon fuel standard.

The cost of production from advanced conversion technologies are still largely uncertain due to lack of commercial demonstration. So that's extremely important to keep in mind. And the feed-in tariff price for electricity's going to strongly influence relative competitiveness of conversion technologies.

And the last thing, I just want to put in an advertisement for the upcoming sixth annual forum of the California Biomass Collaborative, and invite you all to be there. Many of the people in this room will be participating. And I think it'll be able to discuss these issues in greater detail.

Thank you.

ASSOCIATE MEMBER BOYD: Steve, a quick question. Thank you for this indepth, very indepth analysis.

DR. KAFFKA: Too indepth.

ASSOCIATE MEMBER BOYD: In the previous presentations staff identified that come 2050 the need for biomass to meet California's total commitment such as the RPS and biofuels, et cetera, et cetera, leaves us about 30 million bone dry tons short. But that's kind of -- I took that as meaning based on what we know, the 44.4 million bone dry tons, as technologically feasible, versus a potential demand.

I assumed then that -- well, we have to move further out into the area that's now classified nonfeasible, or nontechnically available.

But I infer from your presentation that you see in the future, and your models project that there is enough biomass, in total, available as long as technology and economics and what-have-you work out, to get at it to meet these already fixed goals and objectives. Am I correct?

DR. KAFFKA: Well, I think this modeling is not for the 2050 goal. I think it's more like the closer goal.

ASSOCIATE MEMBER BOYD: Right.

DR. KAFFKA: And it certainly assumes social permission to use resources that could be technically recoverable and available. And that's, as you've mentioned earlier and we all know, is, you know, it's part of the process of governance is getting access to resources, and at what cost and what net social environmental benefit.

So I would not say that this modeling projects that there'll be sufficient biomass for all those purposes. I think that's going out too far, 2050. I think this is much more near-term.

And it's extremely difficult, obviously, you know, as the economist Keynes said, in the long term we're all dead. And I can't -- it's hard to imagine the 2050, for me, personally. I won't be around in 2050, and have to leave a little work for the next generation to do to get there, but --

ASSOCIATE MEMBER BOYD: I was looking at all these young people on our staff now that --

DR. KAFFKA: It's really great.

ASSOCIATE MEMBER BOYD: -- weren't here when I started.

(Laughter.)

DR. KAFFKA: So, no, this doesn't project any security for 2050, as far as I understand.

ASSOCIATE MEMBER BOYD: Okay, thank you.

DR. KAFFKA: Thanks.

MR. ORTA: Well, we are now accepting public comments on the first three presentations. I have some blue cards up here that were given to me. Terrence will be collecting some more. But we have roughly 17 minutes for public comments that we will take from folks in the audience and folks over WebEx. And I will read the names of the folks who submitted the blue cards; and they can come up to the podium and provide their comments.

First I have Phil Reese from the California Biomass Energy Alliance.

MR. REESE: Thanks, Jason. Don't know how I got to be first. It's nice to be talking to you again, Commissioner Boyd; it's been quite awhile.

My name is Phil Reese. I find myself the Chairman of the California Biomass Energy Alliance. This is the trade group of the 33 operating solid fuel biomass plants in California, currently generating over 600 megawatts of baseload power.

I'm going to make a couple of informational statements. I will be very brief. And then I have a number of comments on the first three presentations.

All of the plants are operating under one of three types of contracts. One is what we call a fixed price agreement with the IOU under which the plant has a contract.

The second is being paid short run avoided costs or SRAC. And the third is a bilateral.

The fixed price contracts are so-called by us because they set the price for energy sold to the utility. That price increases 1 percent a year. Very difficult to operate with a 1 percent per year increase in your revenue, and 3 to 5 percent overall increase in your costs.

SRAC is tied to gas, and today it's far too low for any of those plants to be operating. The bilaterals I'll simply describe as starvation level. The summary there is that the entire biomass industry is struggling to stay in business. If it weren't for the subsidy provided by the Energy Commission many of those plants simply would not be operating.

We worry about the end of '11 when the CEC subsidy program comes to an end, and Jason will have to pay us right out of his own pocket.

(Laughter.)

MR. REESE: You see quite a bit on the availability of fuel. I want to make the comment that the problem is not the availability. And I think Mr. Barker's presentation showed that regardless of the definition of technical. The problem is the cost. There's plenty of fuel out there if you can afford to go get it under your contract price. I've said that over and over again for years, with the prices not high enough to make much of a profit, if any.

And I'll be very specific. Mine is the newest and the largest biomass plant in the state. This year we will break even. And the next three years under our fixed price contract we expect to lose money. I don't know what I'm going to do about that yet.

The proof of the fact that it's the cost, not the availability, is rooted in about 2003 when the state set in place a $10 a ton subsidy for the additional collection of agricultural residues with the objective being to reduce open burning of those residues.

There was a sharp upward spike in use of agricultural residues. I'm talking hundreds of thousands of tons for the year the program lasted. And then the Legislature pulled the plug and the use of those ag fuels decreased to its earlier level.

Now, I'm going to shift beyond the staying in business of the existing plants and move to how could we develop any new proven technology biomass generation plants similar to those now.

Let's set aside for the moment the limitation of cost in allowing the development and construction of a new plant. There is another major barrier which I understand is not under the control of the Energy Commission, but it is the major barrier to development of new plants. And that is the subject of providing emission offsets for the emissions from the plants.

The basic rules in air quality management are best available control technology to minimize emissions and providing offsets for whatever emissions are left. In the entire southern half of the state there are no emission offsets available in anywhere near the amounts necessary to permit a new biomass plant.

I have, and can give to you, a list of

nine major, many-hundred megawatt, modern, combined cycle, gas turbine plants that are on hold in the southern half of the state because they cannot get emission offset credits.

And I will tell you, my plant is in Riverside County, and I have been approached by two major plant developers, the gas plant developers, who want to buy my biomass plant and shut it down merely to get the offset credits that would be generated as a result.

Now, when you consider somebody building an 800 megawatt gas plant is going to spend a billion dollars, what it would cost to shut down a 50 megawatt biomass plant and take the offsets, is easily within the realm of consideration.

The offset barrier brings to mind a specific question on Mr. Barker's presentation when he cited some new biomass facilities in counties or locations in California which were in federal attainment. My question is why doesn't he use the state attainment. The state air quality goals are a lot tighter than federal, and there is virtually no place in the state that's in attainment for ozone or PM10 when you look at the state rules.

So I think that use of the federal attainment standards for siting plants is incorrect.

In terms of the competition for fuel between biopower, and I'm speaking of the biomass-to-energy plants, such as exist today, and the biomass-to-ethanol developers, I don't think that's going to be as serious as anyone is concerned with.

We have been working with one of the leading biomass-to-ethanol technologies, one of the unproven ones, but one of the ones that is spending tens of millions of dollars in progress toward commercial demonstration, in terms of co-locating that plant at a biomass plant.

Now, we have a fuel supply infrastructure that supplies 1000 tons per day of wood chips. Out of those wood chips many of our suppliers screen the fines, which most of you would call sawdust.

The fines are of interest to the biomass-to-ethanol plant. So the first synergism is we have a fuel supply infrastructure and a fleet of fuel suppliers that could easily bring the fines that we don't want in our boilers for the biomass-to-ethanol plant.

The second synergism is that there's ligneous left over, about a third of their feedstock is left over in the form of lignin, which is wonderful boiler fuel for us. So they only have to move it ten feet from their output to our boiler input.

The third is that their technology, and I believe most of them require both steam and electricity for the biomass-to-ethanol process. That requires a boiler of some sort.

Going back to the offset question, very very difficult to put a boiler with direction combustion anywhere in California. You can do it on a biomass plant by virtue of installing additional, beyond BACT emission controls on the biomass mass, and using those offsets to provide a boiler for -- to permit a boiler for --

MR. ORTA: Phil, sorry to interrupt you, but we have several more comments to get to within the next 15 or so minutes, so if you can wrap it up. And we will be accepting written comments. We hope that the Biomass Alliance does submit written comments by May 5th. And please go into detail about all of these --

MR. REESE: Okay, okay, --

MR. ORTA: -- in your written comments.

MR. REESE: -- I'll stop here, thanks.

MR. ORTA: Our next speaker is Michael Theroux of Theroux Environmental.

MR. THEROUX: Good morning. I have one point that I'd like to address to Steve having to do with the modeling.

We do see that combined heat and power is certainly a nice tool to use in the process of developing an economic base for biomass power.

When energy began to unravel in California I was on contract with the Forest Service to try to understand what was occurring with our what became stranded markets for biomass.

One of the conclusions that we came to was that if we could, in some way, place combined heat and power units at the source of the feedstock, we would be able to dramatically lower the cost of the acquisition of that feedstock and the shipment of that material on down the hill. So it's a staged mechanism.

We couldn't do it then because the technologies weren't available and the infrastructure for the rule 21 really hadn't pulled into place. But we can now.

And one of the dramatic changes that we've had is in the modular smaller technologies. I would suggest then that we take a look at the modeling capabilities and see if, indeed, we might be able to implant combined heat, cooling and power systems at the source areas.

We found in our time-and-motion studies that quite frequently, and I would agree with Phil, it's not a lack of the material. We found that if folks were geared up and had the wood lot and their saws were oiled and their trucks ran, that we could keep them working. We could gather four to five to six, seven times, depending on the area, the material at any one location that would be able to be used in a combined heat and power location at that small municipality or whatever, to offset the costs of the feedstock acquisition.

So I would suggest that we have an opportunity with the new -- for technologies and a multi-tech approach to a multistaged capability, dropping the bottom out from under the feedstock acquisition for costs that we should take a look at.

Thank you.

MR. ORTA: Gregory Stangl of Phoenix Energy.

MR. STANGL: Good morning. Just to second what the first gentleman said, and the second gentleman, feedstock availability has absolutely nothing to do with our ability to put biomass or distributed generation biomass sources in place. It's really sort of spurious to spend so much time kind of telling us how many millions of tons are available. It really is not the issue.

My question regarding the presentations this morning was I notice that when we get our RPS eligibility certificates, they were inflated by about 50 percent of what we actually asked for.

And since the data appears to be based on those, you know, the summation of those RPS eligibility standards, I wonder if that is affecting your data in terms of how much biomass power you have out there.

Our certificate particularly was 50 percent inflated over what we asked for, and over what the San Joaquin Valley permitted us for.

So, now we do distributed generation, so our systems are much smaller. We do, you know, kind of 1 megawatt, half-megawatt systems, so perhaps that's only relative to us. But it just, it does make me question your data.

The biggest issue I have is that the longest piece in the permitting puzzle was actually the California Energy Commission's issuance of RPS eligibility.

Gasification, and it was talked about in some of the presentations, it can't be done according to your rules. And I know there is something afoot to kind of work on the definition of gasification. But as currently stated, biomass must be combusted to be considered biomass. Since gasification does not combust material, it therefore is not considered biomass.

So then you're left with the definition of gasification, which, if you follow the letter of the law, and, you know, most of the agencies are all willing to look the other way, cannot be achieved in the physical universe that we occupy. There is no way you can do this without the presence of oxygen. Limited oxygen, yes, but if you follow the definition to the letter of the law, it can't be done.

And when one borrows several millions of dollars to do a project, it just, you know, as an owner it makes me slightly nervous that I'm out there, and everyone's sort of agreeing to look the other way so that we can do this, but nonetheless if I really study it, we are sort of in violation.

So if there is an update on the draft that I've seen floating around as far as updating bioenergy, and I think they're all kind of moving in towards liquid fuels, the names, but I'd love to get that at some point.

MS. BROWN: Are you familiar with Assembly Bill 222? There's a bill in the Legislature that I believe addresses the question that you're --

MR. STANGL: I believe that's the draft I've seen. Again, I'm not too familiar --

MS. BROWN: It's been introduced.

MR. STANGL: -- with the legislative process. But, if that's going to happen, that's a great thing.

MS. BROWN: Well, I'm only suggesting you might want to take a look at that bill, and follow it closely and weigh in in the Legislature.

MR. STANGL: Yeah, that's great; I'd be happy to do that. Thank you.

ASSOCIATE MEMBER BOYD: Jason, can you respond to the inflated certificate question?

MR. ORTA: I'm not quite sure what you mean by inflated certificates in the first place.

MR. STANGL: Our project in San Joaquin Valley is a half a megawatt --

PRESIDING MEMBER BYRON: Please come back up to the podium so we can record your information and so the folks on WebEx can hear it. Thank you.

MR. STANGL: Pardon me. Our project in San Joaquin Valley is a 500 kW project. That is the maximum we are permitted for due to a horsepower limitation in San Joaquin.

Our certificate reads 750, and we, you know, we raised that with the Energy Commission. But, you know, we still have a certificate that says 750 kW. So that's what's in the, I think, WEGRIS (sic), or whatever the system is that tracks this sort of thing. That's what's in there.

MR. ORTA: Well, I have your business card up here. I have Gregory's business card. We will look at his RPS certification application and his WREGIS application, and get back to him on that capacity number that he presented.

ASSOCIATE MEMBER BOYD: Okay, I, too, am concerned about what do we tote up to tell us what we've got out there versus what really might be out there.

MS. ZOCCHETTI: We -- I --

MS. SPEAKER: Kate, you need to get up to --

MS. BROWN: Come to the microphone, please.

MS. ZOCCHETTI: Good morning. I'm Kate Zocchetti, the lead of the RPS program here at the Energy Commission. I'm not sure if this is the answer to the question, but just to clarify, WREGIS and RPS use nameplate capacity. I'm not sure if that would --

MR. STANGL: I'm getting -- yeah, --

PRESIDING MEMBER BYRON: Could you come back to the podium?

ASSOCIATE MEMBER BOYD: Sounds like the air quality permit --

MR. STANGL: Yeah, just a quick question on that. If you use biomass gasification you will never achieve the nameplate rating on an engine.

The engine we use is an 1100 horsepower

engine. We're, through San Joaquin, derated to 700 hp. You just don't get the same efficiency with natural gas that you would in an engine.

So, again, my point would be if that's the way your numbers are being done, then your numbers for biomass at large are all inflated by a reasonable amount. Perhaps Professor Kaffka could comment.

But, you know, to us we lose at least 30 percent of the nameplate on gas, you know. And we've certainly done this all over Europe, so we have a number of actual sites that we can point to on that. And 30 percent is -- certainly for us, that's what we lose.

ASSOCIATE MEMBER BOYD: Okay, thank you. We may have to look into whether we have a bookkeeping entry dilemma here.

PRESIDING MEMBER BYRON: These are all good comments. And, you know, I didn't get a chance to comment, Mr. Reese, but I hope that you'll be back up to see us during the other comment periods. I think you had excellent comments; appreciate having them. So don't be discouraged by our schedule here.

MR. ORTA: I have a couple more. I have

Mark Hodges and James McElway (sic).

I also have a question from Ricardo Amon, who's staff here at the Energy Commission. This question is in regards to Mr. Barker's bio presentation.

Ricardo is asking about considering how difficult it is to develop the biomass resource and the high failure rate, what is the economic potential of biomass?

MR. BARKER: We haven't looked into the economic potential right now.

MR. ORTA: Okay. Are there any questions on WebEx?

MR. FLESHMAN: No, it doesn't look like it. No. Hold on, give me a second.

No.

MR. ORTA: Commissioner Byron, as you pointed out, we will go into the offset issue regarding the solid fuel biomass facilities later on in the afternoon.

Greg Morris from the Green Power Institute will get into that during his presentation. And there will be a comment period after that. So, the Biomass Alliance and others would be able to provide comments after those presentations.

(Pause.)

PRESIDING MEMBER BYRON: Mr. Orta, I hadn't seen the detailed schedule until this morning. And I just was checking with Commissioner Boyd to see how we're doing. And we're fine on schedule, so it looks like you're ready to take a break?

MR. ORTA: That's correct.

PRESIDING MEMBER BYRON: Okay, let's take a ten-minute break and try and start up around 11:00.

Thank you.

(Brief recess.)

PRESIDING MEMBER BYRON: This is generating good discussion. Let's to ahead and get started, Mr. Orta.

MR. ORTA: Thank you. The next three speakers for this workshop are going to discuss topics relating to biogas technologies. These presentations will discuss a combination of the USEPA's activity in the landfill gas area, permitting issues associated with digester gas facilities, and finally, some discussion of where digester -- the current status of digester gas technologies and the potential to develop this technology more in the future.

Our first speaker is Pat Sullivan from SCS Engineers.

MR. SULLIVAN: Thank you and good morning. My company, SCS Engineers, is the lead contractor for the USEPA's landfill methane outreach program. And I'm here today representing the EPA LMOP, and providing some information on, you know, landfill gas-to-energy potential here in California, as well as some of the issues in that sector of the renewable energy business that we see in terms of hurdles or obstacles for getting these projects online.

First, California's in the territory 3 of the USEPA's landfill methane outreach program, which includes the western states and other states in the southwest.

This slide shows, in orange, shows the operational projects that we have in the west, including California. And then the candidate projects that EPA is tracking. Collectively there's about over 400 megawatts of power online in the territory 3 using landfill gas.

Let's talk a little bit about

California. Right now EPA has identified around 320 landfills in California that they consider candidate sites that could have landfill gas-to-energy, either today or at some point in the future.

Of that, there are 73 operational projects; 67 of those are direct electricity generation, about 275 megawatts. And then there's another six that are what we consider direct use project, which is essentially in some way collecting, processing and transporting the gas via pipeline to a secondary facility that would then use that gas either in and of itself, or as a supplement to natural gas.

There's seven projects that are currently under construction, six of them being electricity and one that is actually an alternative fuel landfill gas-to-LNG project. And the electricity project is about 36 megawatt of potential that is actually under construction.

The EPA has identified another 35 candidate landfills with about 118 megawatt potential that are in some phase of evaluation, and that the EPA landfill methane outreach program is supporting and promoting.

PRESIDING MEMBER BYRON: Mr. Sullivan, if I may, just a quick question. I want to understand what those six direct use projects are. Is that generating the methane gas and then transmitting it via pipeline somewhere else?

MR. SULLIVAN: That's correct.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. SULLIVAN: So the direct use is all collecting the landfill gas and then transporting the landfill gas to a third-party facility for use. And there's a variety of uses that it can include.

And there's also a variety of levels of treatment. Some literally just compress the gas, put it in a pipeline; send it to a facility who maybe mixes it with natural gas. Some actually do extensive processing to create high Btu or close to pipeline quality gas. So there's a little bit of variety there.

That's one of the areas that we're probably seeing more increase in the sector is in the direct use projects, or the interest in direct use. Part of it is because, as we've found, seen landfill gas projects now that can be successful and be economic transporting gas longer distances than we had first imagined.

So now we have a -- the longest project that we have in the system, not here in California, but nationally, is a 30-mile pipeline for landfill gas. So, no longer does the third-party facility need to be next door to the landfill. And that creates a lot more options.

The LMOP, EPA LMOP actually has a calculator they've developed to estimate the benefits from doing a landfill gas-to-energy project. And it creates those benefits, or calculates those benefits in a lot of different formats. This is available on their website.

And if you take those candidate sites that they're tracking here in California, these are some of the benefits that would be realized from them.

Remember, the EPA landfill methane outreach program is under the climate change program at EPA. So its primary focus is to facilitate greenhouse gas reductions through the control and recovery and combustion of methane. But also through the reductions of CO through the displacement of other fossil fuel power. So that's why the focus here is on greenhouse gas emissions.

Regulations that affect landfill gas-to-energy. You'll notice one thing about this slide is it's all air quality. And, frankly, that's the driver for our projects. That's the -- air quality regulations present the most significant hurdles. They're the ones we spend the most money and time dealing with.

They're not the only regulations, obviously, that we deal with. And someone asked me, well, why didn't you put CEQA here. Frankly, CEQA is a breeze for landfill gas projects. There's a categorical exemption for cogeneration projects that we've been able to use. I've never had to, on projects I've permitted, go anything higher than the negative declaration.

And many landfills include landfill gas-to-energy as part of their own CEQA process, their own environmental impact report for the landfill, itself, or an expansion. Therefore, it's actually already been covered.

So air quality is where the rubber meets the road for us. And frankly, from a regulatory perspective, whether a project happens or not, is driven by the air quality regs.

Here are the federal regs that affect or can affect a landfill gas-to-energy project. And I'll go into these in a little bit more detail in a minute.

Probably the single biggest impact on landfill gas-to-energy projects from an air quality standpoint, is the new source review requirements. And really two areas of new source review, best available control technology or lowest achievable emissions rate. And what that is for the various landfill gas-to-energy equipment.

And offsets. I think we've heard that, and you'll probably continue to hear that today from all of the various subsectors within the renewable energy. Anybody that creates criteria pollutant emissions in their generation of power, whether it's from solid fuel, biomass, landfill gas, digester gas or other biogas, offsets is a huge obstacle for us.

There are new source performance standards at the federal level that affect both landfills, as well as the individual equipment that landfills use to generate power. And that would be turbines, reciprocating engines, boilers.

So we have to deal with those federal standards. But frankly, those are pretty straightforward and they're federal regulations. So there's really not too much we can do here in California to effect those changes.

And then district rules and regs. I'll go into those in a little more detail later. And then similarly, there's federal maximum achievable control technology standards that are promulgated for toxics. And again there are specific ones that affect landfills, reciprocating engines, that we have to deal with.

But as the new source performance standards, there really isn't much we can do here at the state level to effect that. And, frankly, those federal regs are not the main driver. It really is the new source review requirements and the district, or implementation of those at the district level.

District rules and regs that affect these projects. Many of the larger districts in California have their own landfill gas rules that can be more stringent than even the federal rules. And those can affect our projects.

Many of the districts have their own IC engine rules, turbine rules, boiler rules, all that we have to deal with when we're permitting landfill gas projects.

But, again, we've generally been able to comply with those rules, and they generally are not the drivers that affect the project.

The one exception to that might be the South Coast AQMD's rule 1110.2 for IC engines, which essentially, starting in 2012, will hold landfill gas fired engines to what is essentially the natural gas standards.

But between now and then the district is obligated to do a technology review and see if that actual technology exists to achieve those levels. And that will be a big issue for us over the next year as they move into that technology assessment phase. Because that rule, once promulgated, while it only is a South Coast rule, it has the potential to therefore become a standard elsewhere, or at least become the top level of, you know, best available control technology that other districts will look at.

So there'll be some work to be done over the next probably two years in working with the district to hopefully see a reasonable outcome.

But, again, the two biggest drivers to whether a landfill gas-to-energy project happens; whether it can meet the regulatory requirements to be permitted. Or come through the district new source review regulations. And what is best available control technology or lowest achievable emissions rate for the various landfill gas equipment. And how are we going to find and how are we going to pay for the emission offsets.

What about incentives? I'll go through some of the various incentives that are available here in California, or programs that have created incentives. But I'll try to specifically talk of how, you know, we feel they have impacted or helped the landfill gas side of the industry.

You know, clearly RPS has been beneficial, but the RPS, by itself, has not -- did not really create any immediate benefit in terms of pricing. We did not see with the RPS any greater offers in terms of price for our power. And, frankly, in the landfill gas-to-energy industry there was a bit of a disappointment of how the RPS initially played out.

The feed-in tariff has been different.

Clearly in the utilities that are participating in the feed-in tariff program, that has had an effect over the last year in terms of better pricing for our renewable power. So that clearly has had a benefit and would be something we'd like to see -- a program we'd like to see expanded.

Because that has actually brought landfill gas projects that we have set aside because they really just were not economical, and were never going to happen, and now are actually being re-looked at because of the availability through the feed-in tariff program of better rates.

Interconnection standards. Yes, there is a standard process that, you know, obligates the utilities to work with small renewable projects to achieve interconnect. And there's some standardization of the project that's been helpful.

But overall, beyond the regulatory aspects of air quality interconnect still takes the longest amount of time and is the most expensive item for a landfill gas-to-energy project.

So, we're again a bit disappointed in

how that, you know, the interconnect standard, how it plays out in reality. It still takes us, you know, a year and a half to get an interconnect.

And we just had an offer from, you know, a utility who can remain nameless today, where the price of the interconnect was actually over 50 percent of the price of our entire capital expenditure on the project. I mean, frankly, that's not going to work. That project is dead if that's the cost of the interconnect.

And it's very disappointing when you still see those things. So, interconnect has definitely been a bit of a disappointment.

Public benefit funds for the renewables and efficiency. You know, obviously that came through some of the public goods surcharges that were charged to the utilities. That has had a limited value to the landfill gas sector, that we're in line with various other renewables.

And I really am aware of only one project that's actually got any amount of funding on the renewables portion of that program. But the concept certainly is there, and we are -- landfill gas is one of the eligible renewables under the public benefits --

PRESIDING MEMBER BYRON: Mr. Sullivan, what size units are you talking about with regard to the interconnection standard issues?

MR. SULLIVAN: I mean they exist on all of our projects, but landfill gas projects, we have projects that range from small microturbine projects that, you know, 30, 70 kW all the way up to the largest one that I think is being permitted right now is probably about 18 megawatts.

But the most typical size we see are probably in the 1 to 5 megawatt range.

PRESIDING MEMBER BYRON: And the difficulty with the unnamed utility, that was on the order of that 1 to 5 megawatts?

MR. SULLIVAN: Yeah, it's a single -- right now it's -- basically it's two reciprocating engines about, combined, put it right in that 1 to 5 megawatt range.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. SULLIVAN: I guess to summarize from the kind of state-level programs, you know, the feed-in tariff has been very helpful where it's applicable, and that has clearly created some opportunities for projects that didn't exist otherwise; some disappointment in some of the other programs.

Turn to some specific regional ones. One I thought we'd bring out, Southern California Edison has a biomass standard contract. I think the outcome there has been generally positive. I think the standardization of the process has been helpful and SCE, you know, to their benefit, has been helpful in helping some of our projects work through that process.

So I think using it just as an example of a way that they've implemented their program, definitely feel it's been beneficial in the standardization of the process.

Prior to that it seemed like every project was a complete reinvention of the wheel in terms of how we would work through with the utility. So this has been helpful.

I put up a couple of San Diego programs merely to point out, as an example of some of the local things that are going on. And the greenpower purchasing in San Diego, which landfill gas is one of the eligible renewables, as are many of the others that we're talking about today, but we do have a few projects that are applying to that. And are hopeful that there will be some funding.

The sustainable building policy, you know, landfill gas is probably not a good fit for that one. But, we are technically eligible.

There are others, and we've had some -- we've gotten some benefits from various municipalities who have adopted their own RPSs. They've gone beyond the stakeholds, and they have actually been hungrier for renewable power, and thereby resulted in frankly, the biggest thing, better pricing, you know, for the power.

So that's been helpful in a few cities in the San Francisco Bay Area that have been very aggressive. And because of that we've been able to command better power prices than we've gotten from the major investor-owned utilities.

PRESIDING MEMBER BYRON: If I could, just for a moment, with the standard offer contracts we had a presentation from Southern California Edison a number of months ago at a feed-in tariff workshop that we did.

I think they had mentioned by the end of last year there were about six of these biopower standard offer contracts. Is that about right?

MR. SULLIVAN: Yeah, I think that's right.

PRESIDING MEMBER BYRON: And you had indicated that that's offered some standardization to the process, at least with that particular utility.

But is the preference -- in general would the preference be to continue with the standard offer contract, or the feed-in tariffs a bit more attractive?

MR. SULLIVAN: Well, from the economic standpoint, the feed-in tariff has looked more beneficial. I was using SCE as an example of the standardization of the process that was helpful.

But from the economic standpoint, the feed-in tariff has been the thing that we've seen drive up some rates in terms of power price --

PRESIDING MEMBER BYRON: Yeah. I'm very interested in more discussion on the feed-in tariff and the interconnection standards. So, hopefully we'll hear from some commenters at the end of this session.

MR. SULLIVAN: Yeah, and I'm clearly, my expertise is in the permitting of these facilities. I'm not a, you know, RPS interconnect nor feed-in tariff expert. So, I'm speaking just from projects experience of what's, you know, what seems to have gone well, what's helped us out in getting projects through the process, or what hasn't.

And in the case of the feed-in tariff, what's allowed us to get some, you know, prices for power that actually, you know, opens up more projects to viability, economic viability.

Because we've been stuck for a long time, probably a five-year window, at a price range that made it difficult for all the larger projects. And most of those have been developed. And so now we're looking at a smaller size of landfill.

And then under the AB-32 rule there's going to be even a smaller group of landfills that will have to put in landfill gas systems from a regulatory basis, and will be flaring gas. And they'll be even in a smaller range of possible project sizes.

And so, you know, hopefully economics will be there that will support, you know, converting those projects in the future. Because I think that's one of the benefits that the Air

Resources Board wanted to realize, was not only reduce more methane, but hopefully that presented more candidate sites that will be recovering methane that could be then turned to energy.

Barriers. I think I've already talked about some of those as I've gone through the presentation, and I don't want to belabor some of these points, other presenters have talked about them, as well.

There's the ongoing debate with our regulators on what is best available control technology. We understand their desire to ratchet down emission levels and achieve the lowest possible.

But with landfill gas that's difficult. It's an inconsistent fuel, both in quality and quantity. Has a lot of impurities in it. Makes it difficult for a lot of the traditional, you know, post controls that can be used.

And even if they can be technologically achieved, they're extremely expensive. And, again, many of our projects, particularly as we get into the smaller range, are marginal. And expensive add-on controls, we're just simply going to walk away from the project. It's not a case where whether it's a function of whether we could do it, it's a function of it just can't economically be done. And so we'd like to see more flexibility in that area.

Offsets. Again, talked about, and we have the same issues that the others have, availability and cost when they are available.

Already mentioned the utility interconnect. And then realizing that each district has its own air quality issues, own attainment status, we know we can't avoid that. But it sure seems like every time we sit down to do a project, we are -- each air district, and even each utility, or even each just the staff that we get at each of these, you know, those entities, it starts back at ground zero in terms of what do we need to do, and reinvention of the wheel.

And so there just is not a consistent approach that is kind of accepted statewide. It makes it difficult and time consuming.

You know, if I had my druthers what would I like to see and what I think EPA would also like to see in terms of the promotion of these projects is, you know, some sort of valuation of the regulatory programs that kind of affect these projects, and some efforts at making some consistent programs, at least where they can be.

There may be a realization that certain things are air district-specific, but there are some things that I think can be consistent statewide. And it would sure be nice to have that. And that would include coordination with both the state and local agencies.

When it comes to offsets there is a provision in the California Health and Safety Code that provides offset exemptions for certain qualifying and resource recovery projects.

And landfill gas-to-energy is actually explicitly listed there. And there's several criteria. And frankly, almost every landfill gas project meets all of the criteria.

Except there's one at the end that essentially says the applicant shall make a good faith effort to find credits. And while the Legislature was great in, we think, establishing a precedent and establishing a direction that they wanted to see some relief granted to these projects from the offset requirements, they didn't see fit to define "in good faith" very clearly.

So it's been left up to the discretion of the local air districts. And we get a variety of interpretations. Many districts just say good faith is if you can find the credits, you got to buy them, we don't care how expensive they are, sorry.

I can't imagine that's what the Legislature intended, because if that's the interpretation, there's no point in having the statute in the first place.

Then other districts have been very gracious to find ways to grant those credits from their own accounts under this exemption. And that's been very helpful. And the Bay Area AQMD, you know, gets the high accolades for providing credits to probably six projects that I know of, you know, combined maybe over 25 megawatts.

It might not be online today if the district had not exercised their discretion under good faith and decided that because of the cost of these credits and the fact that the costs might jeopardize the project, they would grant them out of their internal bank.

So there is a code out there, the Health and Safety Code, and we'd like to see other districts, you know, find ways like the Bay Area has, and a few other districts, to grant those credits. Because they do have the regulatory backing if they so choose.

Partnerships. The best and successful projects we've seen is when we've kind of linked together the developer, the municipality, the utility and the air district as part of a partnership.

And we've even had cases where a project in the Bay Area, the Bay Area AQMD agreed to provide offsets out of their bank for a good sized landfill gas-to-energy project. In return that applicant agreed to do a pilot scale testing program of some treatment technologies to see if they could achieve lower emissions on a subsequent project.

And I found that to be very creative. The power was being sold through the Northern California Power Agency to some local municipalities in the Bay Area. And those municipalities were present at all the meetings, were very supportive of the project.

And collectively, I think we came up

with a solution that, you know, a lot of people were happy about. If the Bay Area would not have agreed to that arrangement, the project would not have happened. The cost for this case was about 120 tons of NOx credits. And a lot of people in this room can do the math on what that would be. The project wouldn't have existed if those had to actually be purchased on the open market.

So that's an example of how things really got put together well and a partnership was formed that resulted. I think everybody got something out of it. So, hopefully there's others like that.

And then the interconnect. I've already mentioned it. I mean we'd love to see a stronger standard policy to simplify the process in recognizing some of these very small landfill gas. And it goes for some of the other small renewables. They can't afford, you know, $1.5 million of interconnect costs. I mean, it's not going to -- the project's not going to happen.

And so it seems to me that there needs to be a stronger, you know, policy or standard on that than what we're seeing to date.

So that's all I have. The final slide

here is a summary of all of the regions under the EPA landfill methane outreach program. And the individuals at the EPA who are leading that program.

And this program is always available to, you know, assist on projects, whether it's doing a feasibility study, whether it's looking at economic or environmental benefits for the project. They would come out to meetings with regulators and try to help facilitate things. So, they will get involved within reason.

And they have a lot of information. They've developed a variety of guidance documents, and, you know, economic models and other models that are available on their website, which is listed here.

So the lead for this region and for California is Tom Frankiewicz. And Tom couldn't be here today, but he's certainly available, you know, for any consultation.

Thanks.

PRESIDING MEMBER BYRON: Thank you.

MR. ORTA: Thank you, Pat. Our next speaker will discuss permitting issues for anaerobic digester facilities. And that's

Dave Warner from the San Joaquin Valley Air Pollution Control District.

MR. WARNER: Good morning, Commissioners. See if I can get all straightened out here.

ASSOCIATE MEMBER BOYD: Good morning, Dave. Courageous of you to be here.

MR. WARNER: Courageous?

(Laughter.)

MR. WARNER: Very happy to be here, Commissioner Boyd.

As Jason said, my name is Dave Warner. I'm the director of permit services for the San Joaquin Valley Air Pollution Control District. And as I said, I am very glad to be here.

There is a truly large potential for anaerobic digester systems, renewable energy and greenhouse gases, gas reductions from dairy digesters in the San Joaquin Valley.

And the reason I'm here today is to talk about the very real need to include a discussion of air quality as we talk about how to move forward in fulfilling that potential.

(Pause.)

MR. WARNER: Quite simple. First, let's

talk a little bit about some background information. The San Joaquin Valley Air Pollution Control District covers a very large geographical area, from Kern County in the south to San Joaquin County in the north.

Most of you are probably aware that the district is surrounded by mountains except at the north end where we have a pretty consistent inflow of air.

Those conditions and the stagnant air conditions that they provide us, and abundant air quality, are really the perfect recipe for bad air quality.

Pollution that gets generated in the valley tends to stay there and build up day after day until really some air mass, a storm, blows it out, and out through the Tehachapis. Sorry, Tehachapis.

In fact, because of these conditions we have the second-worst air quality in the nation. And we're not that much better than the worst, the more famous L.A. basin.

In the summer we have an extreme ozone problem with volatile organic compound emissions and nitrogen oxide pollution combine in the presence of that sunlight to form ozone, which is the basic ingredient of smog.

And in the wintertime we have the potential for some very bad particulate concentration events. Really PM2.5 inhalable particulates build up just like ozone does in the summertime.

Now, air pollution generates some very serious and well known health effects. I don't want to spend a lot of time on this, but the ozone and particulate emissions cause respiratory and pulmonary conditions from exacerbating asthma to reducing lung function, heart attacks, even premature deaths are directly linked to air pollution.

One study in CSU Fullerton places the human health price tag of that pollution in the San Joaquin Valley alone at $3 billion per year. I'm not going to defend that number. I'm not sure I buy all of it. But, it's a big number, whatever that number is.

And so it's human health impacts that cause Congress to adopt the federal Clean Air Act way back in 1970. There have been a few amendments since then.

The federal Clean Air Act requires states, and therefore the air district, to get to the point where our air is considered healthy. And it tells us how we have to measure whether it is healthy in terms of concentration of pollutants in the ambient air.

If we can't get there, there's significant sanctions. We have a deadline of 2023 to achieve clean air for ozone. And I'll talk a little bit about that in a minute.

But the sanctions that we are faced with if we don't reach those goals of healthy air include significant Clean Air Act fees, as they're called. They're basically fees that large industry has to pay to the air district; and the air district will then take those fees and go out there and try to generate emissions reductions.

The next thing would be that the whole valley would lose federal highway funds. There's some discussion about if one area in a state loses federal highway funds, that means the entire state loses federal highway funds.

And then eventually the federal government takes over the local air quality program.

None of these things are palatable to the residents of the San Joaquin Valley. But those aren't the real driver. The real driver for the air quality regulations are the health issues.

So we put together this 2007 ozone plan, as required by the federal Clean Air Act, to show how we can achieve clean air. And even though we are requiring every feasible VOC control and every feasible NOx control on the existing stationary sources in the San Joaquin Valley, we still can't project through our modeling that we're going to achieve clean air by 2023. We have to rely on these technologies that will come along between now and then.

So the result of all this is that we have the toughest air quality regulations in the nation.

So that's my world, the worst air quality in the nation, some of the worst, costing the local economy really billions of dollars in health-related costs. And planning on adopting every feasible regulation.

And, of course, these are kind of the high, the really high fruit. We've spent 30 years regulating and getting the reductions from the low-hanging fruit. And still not getting to the point where we can accurately project that we're going to achieve clean air by the federal deadline of 2023.

So, as I mentioned, for the last three decades we've been regulating stationary sources of air pollution in the San Joaquin Valley. And requiring permits before sources of pollution, stationary sources of pollution can construct or operate.

Not only does nearly every one of those sources have a specific rule that addresses the emissions from that type of equipment, but new and modifying equipment is faced with an even more stringent requirement we've heard of already today, in our new source review requirements, including best available control technology and emissions offsetting.

Public notification of everybody that might be impacted by a permit is another one of the requirements.

What I'm going to talk about most of today, the most of the rest of my conversation here, is best available control technology.

So, with that as a background for the

San Joaquin Valley's air pollution issues, let's talk just briefly about dairy digesters. Most of you probably are quite well aware of what a dairy digester is. But in case you don't, a dairy digester is a covered lagoon or a tank that holds the waste from the cows at a dairy. With antigens, with bacteria in the waste, produce methane. And if that lagoon is covered the methane gets captured and traps that methane.

Which is a very potent global warmer. It's over 20 times more potent as a greenhouse gas than the we hear more commonly about, carbon dioxide.

It's important that everyone realize also that methane is not one of those pollutants that we worry about at the ground level. It doesn't have immediate impacts on human health. It certainly is a potent global warmer, but it doesn't contribute significantly to the formation of smog in the San Joaquin Valley.

So if we can do something with that captured methane, like burn it and turn it into electricity, we've reduced emissions of greenhouse gases and created a renewable power source, and that's fantastic. That's a great thing.

We also get small amount of volatile organic compound reductions. That's another great thing. However, there's a cost; there's a potential for very large NOx emissions increases when you combust methane.

Now, how large are we talking about? Well, you know that plan I was talked about, the 2007 ozone plan, that entire plan, if you look at all of the control technologies that are aimed at stationary sources that we're going to adopt between now and 2023, we think we'll get about 8 tons per day of NOx reductions. This is on top of hundreds of tons we've gotten in the past. But from this point on, 8 tons of NOx reductions.

With a potential of maybe 250 megawatts of dairy digester power in California; you know, most of that's in the San Joaquin Valley. But let's conservatively say about two-thirds of it is in the San Joaquin Valley.

We're talking about a 5 ton per day potential NOx increase. That virtually wipes out all of our planning efforts between now and 2023, all of the rule adoption possibilities that we have to get emissions reductions out of stationary sources.

So it is a very very significant issue. And that's why we're here to talk about it today.

Doesn't mean that dairy power is dead in the water. There are some low NOx and no NOx technologies that are available to turn dairy digester methane into power. So let's talk about some of those.

We'll talk about kind of a pie-in-the-sky one first, fuel cells. You know, we've been aware for years and years that fuel cells are extremely clean, almost no emissions of concern come from fuel cells.

They also do a great job of turning gas into power. They're significantly more efficient than an internal combustion engine. The problem has always been cost, and we recognize that. Fuel cells are very expensive. Things have been coming down now, but they're still expensive.

There are grants out there available. And some folks, the City of Tulare wastewater treatment plant has been successful in putting together a package of grants that made their fuel cell, which they now have installed and operating, actual cost effective, when compared to internal combustion engine power. The cost was almost identical. And they now have an operating fuel cell.

Another great technology, from my perspective, is the injection of biogas into a natural gas pipeline. There is an operational system in the south valley. Very pleased to have been a part of getting that rolling.

There's permits for several others. You could be heating your morning tea with gas from a cow. That's pretty cool.

These are also technologies that are very very low NOx. Really the only NOx associated with it is from occasional flared releases of methane.

But fuel cells are expensive; natural gas pipeline injection is really not everybody's option. So far, you still have to be fairly close to a pipeline of a certain type. And really, the allure of using dairy digester gas, to many, is the ability to produce on-farm power.

So, there are some technologies that are available that will get us that part of the equation, as well.

PRESIDING MEMBER BYRON: Mr. Warner, I can't help but ask, it seems as though you like the gas pipeline injection, as long as I heat my cup of tea in another district, right?

MR. WARNER: No, it's fine. It's just displacing natural gas usage that's already occurring in the San Joaquin Valley. It's absolutely perfect solution. So it can be in our valley, too. It can even be my pot of tea.

So let's just talk real briefly about some of these combustion technologies that can help us produce onsite power.

Microturbines. Microturbines could be permitted in the San Joaquin Valley, we think. We haven't had a proposal for one on a dairy digester, but we think they're there.

Unfortunately, they have a really bad reputation due to some failures in early installations. They're actually up and operating in other states. New York has a dairy operating a few microturbines right now.

They're an option; if you're interested in this kind of business, take a look at it. I think it's quite a shame that they've been shut out of the market effectively here in the state of California. I think they're robust. I think they're easy to get low NOx emissions. So we're hoping to see some more in that arena.

But the approach --

ASSOCIATE MEMBER BOYD: Dave, what about the cost of microturbines?

MR. WARNER: I'm sorry?

ASSOCIATE MEMBER BOYD: What about the cost? Are they costly?

MR. WARNER: No, I don't believe they are costly when you compare them to a lean burn engine, which is the direction most people are trying to go. I could be wrong there. Maybe there's some people that can provide some comments on that.

There is an approach favored by most of the people we've talked to, and that's burning digester gas in an internal combustion engine that drives a generator to produce on-farm power.

Unfortunately, internal combustion engines really are dirty pigs when it comes to NOx emissions. They can be cleaned up some, but without exhaust controls on an engine they just can't be clean enough in the San Joaquin Valley.

For instance, lean burn engines can be tuned for kind of low NOx, about 50 ppm. That's really good when you look at an internal combustion engine. And we've heard about them being able to achieve 35, even 30 ppm.

But to put that in context, these emission rates are more than an order of magnitude higher than a clean, combined cycle, natural gas turbine at 25 to 30 times higher. That's significant.

ASSOCIATE MEMBER BOYD: So, lean burn wouldn't make it in the district?

MR. WARNER: That's correct, not without exhaust controls.

So, those stringent new source review rules that I mentioned require that these types of installations be equipped with the best available control technology. And that means you have to get your emissions down to .15 grams per brake horsepower hour. That's essentially 9 ppm to 11 ppm depending no the type of internal combustion engine.

For those of you that know power plants, even with controls that's about 0.5 pounds of NOx per megawatt hour compared to something like .06 for a combined cycle plant. So, still an order of magnitude higher with the controls.

But those are permittable, since they

are equipped with the best available control technology at that level, we are able to go through the permitting process.

So there are some engine controls here that I mentioned that we are aware of that can get to these lower emission rates. Rich-burn engines can be equipped with relatively simple three-way catalyst systems, similar to the catalyst on your car.

Gallo Farms has done this with marginal success. When the system is operating well, it does achieve the 9 ppm and considerably lower NOx emission rates. We're working with them through some engineering issues. They actually added a second engine onto an existing gas system that was already powering one engine. This newer engine was the one that had to meet the 9 ppm emission limit.

And in our opinion they didn't do an adequate job of upgrading the engineered systems that deliver the gas to the engine. They're working with us on that. And we have great hopes for the success of that program.

But everyone really wants to use a lean burn engine because they're quite a bit more efficient. There's a great savings in fuel costs.

And lean burn engines can be equipped with SCR, selective catalytic reduction, which is not a simple technology in anyone's book. It requires ammonia, an ammonia tank, carefully metering ammonia into the exhaust stream in a very controlled way, very critical temperature ranges.

There is a dairyman in the San Joaquin Valley who has installed a truly top-notch dairy digester, which has allowed him to head down this route. It's a tank digester with very little hydrogen sulfide emissions coming out of the digester. He is in the process of starting his selective catalytic reduction system on a very nice, glass core, lean burn engine.

We've talked to at least three, I think perhaps it's four, selective catalytic reduction technology vendors that will guarantee this .15 gram per brake horsepower emission rate.

And then recently we've been approached by a company called California Bioenergy, who have developed what looks to be a very very cool technology. Uses the simpler three-way catalyst system on a lean burn engine. Which those of us in the air pollution world have been telling people that's not possible for years and years.

The technology appears to be very well developed; it's a very impressive set of folks that I believe will probably become, in fairly short order, some major players in the on-farm power production in the San Joaquin Valley. Very happy to be working with them.

I want to end it with where do we go from here type of a discussion. First of all, the air district really is looking for ways to help these technologies move forward. We recognize the important in California of reducing greenhouse gases.

We think equally there's a very important component to renewable power sources that dairy digesters can fill. We just can't do it at the expense of the health of the people in the San Joaquin Valley.

And so we've been working hard to come up with these technologies that can help satisfy all of those goals.

We love pipeline injection systems, I'll say that again. We'd be a supportive partner of anyone that wants to go down that path. We continue to look for opportunities to get fuel cells operating at a dairy. That's going to happen some day, probably in the next couple of years.

We also want to have solutions for people that want to get going today, people that want to start internal combustion engine on their farm. One of the things that I didn't mention about the California Bioenergy folks, is part of their business plan is actually to be the operators of these power plants on the dairies, rather than relying on the dairymen to become a power plant operator.

I think that's a really critical piece of their business plan. In fact, it just makes sense, dairymen are really good at getting milk out of their cows, but they're not really good at operating a power plant, especially the complex type of power plant that really has to be in place to meet our air quality goals.

So there's also the potential of multidairy gas manifolding. We've been talking to some in the dairy industry about a project like this, where multiple dairies will actually just pipe their gas to a central power plant. You get the economies of scale, plus you get the benefits of having an onsite power plant operator rather than a farmer operating that power plant.

We also have looked to ways to provide true flexibility in the permitting processes for folks that come to us, they want to get an engine going. They say I'm willing to install these technologies, but I'm concerned that even after I do all this, I'll be in the same situation as Gallo Farms.

We're having difficulties meeting that emissions rate. And we've worked with them to come up with permitting processes that give them a permit that allows, actually allows us to go back and increase that .15 grams per brake horsepower emission rate. If we go through this analysis, this process of fine-tuning and doing the best we can with the technology, and we still can't reach those emission rates.

We understand these guys are stepping out there on the edge. We're trying to provide as much backup for them as we can.

We're also working with other agencies and industry representatives to find ways to fund these advanced controls that are necessary in the San Joaquin Valley. And be happy to work with anybody that is wanting to move in that direction.

We also are looking forward to helping fund research projects that will help prove out tomorrow's technologies, perhaps that fuel cell.

With that I'd like to just give you some contact names. The same phone number will get you to all of us. My name's there at the top. Ramon Norman is an air quality engineer on my staff. I put him up there as probably one of the leading experts in the nation on how to control NOx from digester combustion processes. Very very full of information.

We have a very active grants and funding program in the San Joaquin Valley. Samir Sheikh is the director of that emissions reduction incentive program. He is also very knowledgeable about dairies. He used to work for me in my program. And so he is an excellent contact for those of you that are looking for funding assistance grants. He's working with the CEC to work on various grant opportunities, as well.

And Kevin Wing is his right-hand man on the dairy programs.

So, with that, I'm going to close it down.

MS. BROWN: Dave, could I ask one question?

MR. WARNER: Yes, ma'am.

MS. BROWN: How does the recent endangerment finding by USEPA affect these dairy digester projects, if at all?

MR. WARNER: I don't see a direct impact. The endangerment finding means that EPA will have to figure out how they're going to control greenhouse gases either through the Clean Air Act or amendments to the Clean Air Act.

But it will take awhile for the ramifications of that to be felt at the permitting level.

MS. BROWN: Probably a couple of years?

MR. WARNER: Your guess is as good as mine on that, Commissioner.

PRESIDING MEMBER BYRON: Ultimately, though, I had a similar question. I just want to make sure I'm thinking about it correctly.

As you indicated, methane's a high GHG ratio gas compared to CO2, for instance. Are you going to have to look at tradeoffs then when we look at things like dairy digesters, methane being released instead of combusted?

MR. WARNER: We actually -- I mean this whole discussion today is a discussion of the tradeoffs. And as far as, you know, the direct health effects, we still are, you know, and I don't foresee a future in which methane becomes a more significant health concern, immediate health concern than ozone at ground level for the breathers of the San Joaquin Valley.

But, you know, stranger things have happened.

ASSOCIATE MEMBER BOYD: I was going to say, be careful, you're tramping on thin ice now. With the endangerment finding for seven different gases, that's starting down the path to designating ultimately perhaps criteria air pollutant status. And then that means all air quality folks have to vigorously pursue that.

But you may be right that NOx or that ozone still is public enemy number one for air quality people. It's a long time before we get there, so no sense debating it.

MR. WARNER: I agree with you. NOx is the primary precursor for both our ozone and our particulate problem. And we know those are causing direct health problems right now. And so those are the things we're going to have to weigh as we move forward to see where EPA goes with this endangerment finding.

PRESIDING MEMBER BYRON: Thank you, Mr. Warner.

MR. WARNER: Thank you.

MR. ORTA: Our next speaker is Allen Dusault from Sustainable Conservation.

MR. DUSAULT: Thank you. Let me just have a quick observation that the permit engineers from the air districts may be from Mars and the permit applicants may be from Venus. There's a very different story when you look at dairy digesters and many other types of projects, you get very different perspectives. And I think that book that referred to men and women also applies in this case to the permit applicants and the engineers.

And I know -- let me also observe, I know Dave has a tough job. I actually had a very similar job a number of years ago. I was a regulator and enforcer, and I had to go up before the public and do unpopular things. So let me just express my sympathies before I beat up on Dave.

(Laughter.)

MR. DUSAULT: Just to give a quick bit of background about Sustainable Conservation, we are a nonprofit environmental organization. And we focus on agriculture primarily. And we don't take industry money; we're grant funded.

But we really have to -- our model is to put projects on the ground, that is we're not really focused on legislation and policy and that type of thing. We're looking to make a difference, to actually get projects going.

And when you move from the theoretical, the 20 percent RPS and all the other things, to actually implementation, there's a lot of things you learn. And that is there's a lot of complexity and difficulty for getting projects going. And the landfill gas people are very aware of it, and the biomass people trying to get woodwaste and all the rest of it. They're very difficult to get, not just the permitting, but the whole process can be difficult, interconnection and everything else.

So, I discovered how difficult by actually having to do these projects. So I'm speaking from my own experience.

I think everyone's aware that -- maybe not everyone, but California's the largest dairy state in the nation. And with all those dairy cows and all that milk comes a lot of manure, which does provide an opportunity for energy.

And, of course, the concentrations in the San Joaquin Valley primarily, we also have some of the worst air pollution in the country. And certainly cows also contribute to methane emissions, which are an air pollutant, but not a criteria air pollutant, or not a regulated air pollutant by the air district, understandably. At least at this point.

But there's a lot of methane out there. It's available for reuse. And we're capturing very little of it.

The opportunities with digesters -- and by the way, there's other technologies for capturing this energy. There's gasification systems and other things that can be used for turning the agricultural waste products into fuel or electricity.

The digesters is one we focused on, but not just that. And we know there's similar issues with other facilities because we're working on both in biofuels and gasification and some other systems. So there's various on all these types of projects.

But the digester projects we've worked the longest on. I think we've been doing it now for eight years. And basically the type of digester you're going to do is dependent upon the type of dairy system you have, how you manage the manure.

And there's three basic systems and some hybrids. But we're seeing most common is the covered lagoons, but I think we're seeing more complete mix and plug flow coming in now. And we're seeing those probably have the better opportunities for the combined heat and power, which is becoming increasingly important to the economics.

And when we look at the opportunities for capturing the energy value you have really four options. The last one I list here is probably the least attractive for a couple reasons.

One is the greenhouse gas value, alone. Really, it's hard to make the numbers pencil out. I don't know of anyone who's been able to do that,

that is cover an existing lagoon and make the greenhouse gas value pay for that.

There are some projects in other states, but they have a different set of regulatory hurdles. And they're different systems.

The biomethane option is one that's been talked about. I talk a bit more about it today. It's one that we actually pioneered, that is Sustainable Conservation pioneered, going back about five or six years ago.

And, in fact, with one of the Commissioners here, went to Sweden to look at what they're doing in Sweden with biomethane, which is a lot further along than the United States. And partly because they have more resource constraints than we do, and I think they have no natural gas of their own.

So they've looked to take full advantage of that opportunity, both for the pipelines and for biofuel. They've been running Volvos and trucks and buses on biomethane for quite some time now. And, of course, the electricity option.

Let me just start with the electricity option in terms of the generating power. So, it's important to point out that digesters don't just, you know, contribute to NOx. And actually it's the engines that do that.

But they do capture ammonia. The do capture H2S and probably very significant quantities of that. And that's a PM precursor. As well as destroy some VOCs.

There's never been sort of a health study that I've seen that looks at what the benefits of capturing those emissions versus the increase in NOx. But that would be an interesting study if you could do it.

But the price for the power has made them more attractive in the last year or so because before we couldn't sell power. I say we, the dairymen had to use the net metering contracts, and they were less attractive than the power sales. With the new feed-in tariff that is a more attractive option.

But the permitting barrier is now looming probably as the largest hurdle to getting these funded and approved. Particularly funded.

So, I think it's important to recognize that when we look at emissions we're increasingly looking at the life cycle emissions. We're doing that with the low carbon fuel standard. It's probably useful to do that with the air emissions, too.

And if you do that, based on the best information we've been able to find, you may actually have a net benefit from dairy digesters in terms of just looking at NOx alone. Less NOx emissions than combined cycle gas turbines, which is the gold standard against which the emissions are measured.

That's an important recognition, and something that we, as air districts and regulators, the ARB and the Energy Commission, look at these larger externalities that oftentimes are outside of California, but also occur within California sometimes.

We need to be considering those, because if we're exporting our air pollution, and we're doing that with our coal plants, which at 20 percent of our power, the mercury and lead and dioxin that are being generated in Arizona, for example, other people are breathing those.

And we can offset those emissions. And I think in the larger scheme of things we need to consider that.

One other point I'll make is when you

look at the BACT determination, and Dave is bound by that, that's understandable, the BACT laws, in every case where we have installed or about to start up an engine where there's been a BACT determination on a dairy digester, internal combustion engine, they were based really on the claims of salesmen.

Going back to Gallo, originally, where the salesman came in and said, we can do that, we can meet that goal of 9 parts per million. When push came to shove, they actually didn't guarantee it. And in the fine print they didn't take any financial risk. That was borne by the dairymen. And he's gone through about nine catalysts right now, and quite a bit of money, almost a half-million dollars.

So when we talk about shifting that risk of putting new technologies on that really haven't been demonstrated, it is a significant risk. The dairymen that see that happening say, I'm not going to do that type of project, because we can't bear that risk. It's too great. The benefits from the digester is just not worth it.

And so that gets out there into the -- among the dairymen and others, and it really shifts the level of interest significantly away from doing these projects.

This, by the way, is just from a PowerPoint that came out of NREL. Dairy digesters, they're under DG, dairy AD, that's on the right there versus the combined cycle, gas turbine, NGCC on the far left. So the lifecycle NOx emissions really are significantly less. And that's important to recognize.

Digesters are also baseload power. And that's important because providing baseload power allows you to offset coal plants and other types of emissions that may be occurring outside of California.

And we're also destroying methane, unlike wind and solar, which are, in a sense, which are good, but offset existing fossil plants.

And a study done by the California Public Utilities Commission really gave a big vote of endorsement to biogas facilities in terms of their benefit/cost ratio.

PRESIDING MEMBER BYRON: Excuse me for interrupting. Do you have any capacity factors for the dairy digesters that you're talking about?

MR. DUSAULT: Well, right now we only

have about seven or eight megawatts of power. And that's going the other direction right now, I was about to mention.

And we funded about -- I say CEC -- I should say CEC funded about 18 digesters in the dairy power production program. That was the SB-5X money.

Most of them got built but not all of them. And not all of them became operational. Those that have become operational, and they're both in the central valley and in the Chino basin in southern California in the South Coast Air District, six of those have shut down in 2009.

In the case of the San Joaquin Valley, it's the retrofit rule that led the dairymen to decide it wasn't worth it. And I think there's a related reason in South Coast, but I am not as familiar so I'm not going to -- but my understanding in talking to the people there at Inland Empire Utilities Agency, that they shut them down, the regulations were a big part of their leading them to do that.

So, we're going in the other directions now with digesters in terms of we're shutting them down, and not really building any more, at least hardly any more.

PRESIDING MEMBER BYRON: Okay, well, that's good information. I wish I'd have known to ask that question. But the one I was interested in was the ones that are operating, about how much of the time do they operate capacity-wise?

MR. DUSAULT: Roughly 85 to 90 percent. The limitation on that, on my saying that is with the new ones coming in, with the new technologies, probably won't be operating at 90 percent. Gallo certainly hasn't.

If we're talking about just lean burn engines, that's about right. With the new systems, it's anyone's guess.

We see with microturbines, for example, the first couple years where they were used, they were at 40 and 50 percent. That's a reason there's not really any dairies that are interested in doing microturbines in California.

We did quite a number of them, and they didn't work. They can be made to work potentially, but the cost and the mean efficiencies, compared to internal combustion engines, make them very undesirable economically.

PRESIDING MEMBER BYRON: Okay, thank

you.

MR. DUSAULT: So, going into biomethane. That's a process that basically takes 60 percent, maybe 65 percent roughly. The methane that comes out of a digester, to about 98, 99 percent, depending upon the utility's requirements. Somewhere in that range.

Which makes it very clean, pipeline quality. Displacing fossil, natural gas. You have to take out the contaminants. And you do have to meet pretty stringent standards for quality and supply sufficient quantity.

Again, I mentioned Sweden. They pioneered the technology to do much of the cleanup technology. And it's really technically feasible. It's a question of cost typically. Does it -- at any given dairy, any given situation, is the cost justified. And there are some contingencies to that.

Let me talk briefly about the -- there's two companies looking to build, and one company has built, a biomethane injection system. The Vintage Dairy or Dave Alper's Dairy in southern San Joaquin, they are now operating; they're now injecting that biomethane in the pipeline.

And let me recognize that PG&E, to its credit, early on recognized this opportunity and actually helped promote these facilities and wrote some contracts for buying the natural gas, the biomethane.

The company, and Bioenergy Solutions also has a number of other dairies under contract. I think there's one other under construction, but there's been some financing issues that they've run into.

And they also face -- you need a certain energy density, certain number of cows. And it's about 10,000 cows. Typically you're now looking at dairy clusters. But the financing has proved one of the most difficult barriers to doing more of those facilities.

The other company doing that is Microgy. Their model's a little different. The Bioenergy Solutions is mainly focused on dairy manure, alone. Whereas Microgy's going a codigestion, as well. And they take offsite waste in, which means they have not so much -- they don't have an air quality issue, per se. They have a water quality issue.

There's both nitrates are typically

brought in with the offsite waste, as well as the salts, which again we have problems with the groundwater in the central valley. So that was a limitation in terms of getting the Water Board permits.

Those were eventually obtained, but it took awhile. And unfortunately they're now -- their construction is stopped again because of financing problems.

I've mentioned PG&E. Sempra Energy is also, my understanding, negotiated some contracts to buy biomethane. The issues are primarily related to proximity of the pipeline and the price of natural gas.

We have seen in the last couple years the price fall by something like half, which has significantly affected the economics of these facilities, and made it more challenging to get them to pencil out.

But certainly there's developers out there that want to do them. It's just the banks have not been that willing to lend recently.

And this is my final alternative for using the energy. And I talk about dairy digesters. It's really not just dairy digesters.

There's any number of other sources, food processing plants and other sources of waste where you can produce anaerobically biomethane.

But the opportunity in terms of the greatest environmental benefit, particularly air quality benefit, is displacing diesel fuel. And, again, Sweden pioneered this, but you can turn the biogas into biomethane for vehicle fuel. And actually displace quite a bit of diesel.

And you could actually run most, or all, natural gas powered vehicles in California, actually quite a bit more than that, on the biomethane just from dairies.

And we have an actual dairyman now operating two trucks. He's the first in the United States to do that in my understanding. And he's running, it's a long trip, it's a 300-mile roundtrip on one tank of gas, believe it or not. There's some extra tanks he's installed. And the cost is about $2 a gallon equivalent. That's still an estimate, but that's pretty attractive. Diesel at, you know, $2.50, $3 a gallon, it starts to look pretty good.

There's some other barriers to that, but that would be ideal if we could get more trucks, diesel trucks, running on biomethane.

And, again, you have carbon-negative fuel in this case. You're actually, because you're pulling methane that otherwise would be released out of the air, it's having a significant net environmental benefit, certainly on the carbon side, but on air quality and other issues, as well.

So, just to wrap up. Less than 1 percent of the dairies in California have installed digesters. And the regulations are proving really daunting. They have scared away a lot of investors.

There's actually -- I probably have one or two investors a week coming to my office. And over the last six months or a year, virtually of them have just decided to go elsewhere and invest in the technology.

And the state agencies, and we've tried to work with -- we have worked with the agencies, different air districts and CARB and CEC. There does seem to be -- the agencies working at cross-purposes. I'm sure that's not the first time you've heard that, but that is a significant problem where you have one agency pushing, you know, greenhouse gas reduction, another just focused on air emissions.

It would be nice to have better coordination, but that's probably a perennial problem.

So, in my opinion, digesters are the most environmentally friendly technology we have for renewable energy and renewable fuel. And I think there's quite a number of other people that agree with that.

There are some tradeoffs. There's no perfect solution that I know of. We need to overcome the regulatory and other barriers. And sustainable conservation is actually doing that.

For every problem we identify we also work on solutions. And that includes NOx emissions problem. We've been working very diligently on that. We started six years ago and we continue to work on that. We're hopeful in the long term we can solve that, but the challenges are keeping the industry alive in the short term.

The unfortunate part is there's only about a handful of digester developers nationally right now. And until that equation changes, we're not going to be able to significantly make some inroads, certainly not to address the methane issue, but even to get the funding we need to get the technologies developed for pollution control. That's certainly been very difficult.

With that, I'll stop.

ASSOCIATE MEMBER BOYD: Allen, I probably should have interrupted you on your slide about biomethane for pipeline injection, when you said the financing had stalled, and then your sub-bullets, the price of natural gas has fallen significantly.

I understand financing installed projects. My knowledge is that it had nothing to do with the price of natural gas, had to do with the current state of the economy and the position of lenders and what-have-you.

And therefore maybe you can educate me better. Has the price of natural gas, which has fallen, resulted in any failure or in stalling a facility from being built?

I would think because gas utilities get an RPS credit for the use of this gas, it's dedicated, you know, pledged to a natural gas power plant, that ought to be enough of a pull to facilitate the state of the price of gas.

But as I said, I'm quite aware of what the current financial market has done to some projects that were really all ready to go.

MR. DUSAULT: So, you raise a good point. So there's two issues. One is the price of natural gas, which does affect what the economics look like. And let me just say the contracts with the utilities are confidential.

So, it's not public information as to what the numbers are. And most of those were written two years ago, two or three years ago.

So I don't know exactly what the numbers look like. What I've heard -- we do know the price of natural gas is dropping. Typically the contracts have some relation to the price of natural gas.

That is, it's unlikely that a utility -- I don't know, they can speak for themselves -- will write a contract for the old natural --

ASSOCIATE MEMBER BOYD: I'm hoping they will later today.

MR. DUSAULT: I think there's going to be a comment after my talk from one of the utilities.

So, partly the answer is I don't know.

Separately, there certainly is -- there would have been a financing problem probably anyway. It's likely exacerbated by the price of natural gas, because there's some relationship between the ability, certainly going forward on new contracts, to get a contract that was as favorable as it was two years ago.

But in terms of existing contracts and the price of natural gas, they're probably not related. The financing was separate and distinct an issue that has stalled the project, the Microgy project, in any case.

ASSOCIATE MEMBER BOYD: And I have to comment on your state agencies are acting at cross-purposes comment.

It's hard to defend that statement based on the last couple of years, but the state agencies really are working together trying to address all the dilemmas that face these issues.

And, you know, talking a bit out of school, we even had a meeting in the Governor's Office a week or so ago and we're still all trying to get this resolved. We'll probably show up in the San Joaquin Valley in the not-too-distant future to talk to local people about getting this resolved. But it is a problem.

And with that I have to run to my lunch meeting.

PRESIDING MEMBER BYRON: Commissioner Boyd has to leave. He'll be back.

You know, these last couple presentations were very good, very informative, notwithstanding the cross-purposes issue, notwithstanding the financing issue. How about technology?

Mr. Warner brought up the lean burn engines with the three-way catalyst technology is the new and improved way to reduce NOx. Any comment?

MR. DUSAULT: Yes. My understanding, that technology has not been installed anywhere yet. Someone -- I've actually talked to, I think, the same developer, saying they're hoping to install it, and they're hoping it will work. And I do, too.

But it's difficult for a project developer or dairy to make an investment on a hope. And that happened in a sense with the Gallo Dairy. And there's another dairy that was mentioned, also, that is installing SCR. They also hope it will work, but they don't know.

They were far enough along, they'd already built their digester. They kind of had to, were forced to do the SCR. But if it doesn't work, you know, it's a bit of a difficulty.

PRESIDING MEMBER BYRON: Okay. Thank you very much. I think we'll go to some public comment period, so we can eat lunch eventually, right?

MR. ORTA: Thank you, yes. Just wanted to let everybody know we're about 23 minutes behind schedule. Hoping that I can get in, if that's okay, 20 minutes worth of comments.

I would like to call up Evan Williams of Cambrian Energy.

MR. WILLIAMS: Thank you. My name is Evan Williams. I'm the President of Cambrian Energy. And over the last 29 years we have developed 50 landfill gas-to-energy projects, 20 of which have been here in the state of California.

I would like to actually ask for the Commission's support of what I think is going to be something that's going to remove an impediment to development of potentially hundreds of megawatts of landfill gas projects in California.

I'd like to tell you a success story that occurred recently. And then tell you why that story, under the existing environment, could not happen in California today. And then I'd like to suggest a fix for it.

In August of last year we teamed with three other California companies, one of which is Clean Energy, which is the largest vehicle fuel supplier in the transportation industry, largest shareholder T. Boone Pickens.

And we acquired an interest in one of the largest landfills in the state of Texas.

We have another California company which is SCS Energy. Part of SCS engineers providing operations.

And we teamed with the San Diego Office of Shell Energy North America to take renewable natural gas from that landfill in Texas, working with the Commission, getting it transported here to California. And it is now being used to generate renewable electric power under your eligibility guidelines.

So, that's going to be approximately 50 megawatts. That's creating those without any new emissions here in California. We're basically displacing fossil fuel natural gas with a renewable fuel.

I can't do that today in the state of California. And the reason I can't do that is an existing regulation that, in effect, has created, you know, all the tariffs of the pipeline companies in California a requirement that says they will not accept landfill gas derived renewable natural gas into their pipelines.

And the reason for that is a law that was passed 21 years ago by Senator Tom Hayden, that dealt with vinyl chlorides that's present in landfill gas, and said if there's any vinyl chloride present, and it's put in, there's a $2500 penalty on both the developer and the pipeline company. And there's a twice-a-month measuring requirement.

And that requirement has, in effect, created a total ban on the acceptance of natural gas. California's the only state in the Union that has that requirement.

It's a bad law because it came out of very bad facts. It came out of the operating industry's landfill, which is a class one hazardous waste landfill in southern California that ultimately became a SuperFund site, that was not collecting all the gas.

All the studies that related to the adoption of that law dealt with the effects of the -- the health effects of vinyl chloride from escaping natural gas.

But the law that got imposed did not deal with the escaping natural gas, it dealt with the collected natural gas that was used as a fuel. And vinyl chloride, when it's burned, actually burns and gets destroyed more effectively than does methane.

It also is injected in the pipelines where it's basically diluted with fossil fuel natural gas.

So we have a law in effect right now, the only one here, that has imposed the vinyl chlorides that come out of landfills basically come from chlorinated solvents. Those are degreasers; they are used in dry cleaning.

By law you're not supposed to put those in a class 2 landfill. They go into class 1 landfills, which is the type out of which this regulation sprung.

But the regulation doesn't apply just to class 1 landfills. It has been cast very widely in terms of its net to apply to all California landfills.

There was testimony given, and actually a study done, by the Battelle, the Pacific Northwest Labs, that indicates the source of basically vinyl chloride from landfills is not PVC, it's these chlorinated solvents. They're in extremely small quantities in class 2, and the largest preponderance of them is in class 1 hazardous waste landfills.

We posed a solution to this, and we hope to get this put into motion later today, is basically to amend the existing state statutes to apply only to class 1 hazardous waste landfills.

There are vinyl chlorides that appear in digester gas because of the commercial industrial waste that happens there. However, there is no law that prohibits processing a digester gas and putting it in a pipeline.

Your own regulations say landfill gas from out of state is welcome. And it's not prohibited by this law because it is not initially introduced into a California pipeline.

So we've got an economy of regulations right now. One we took advantage of; we've got roughly 50 megawatts and growing. And the other is an issue.

And why is this important? You can say, Evan, gee, why don't we just make electric power. And this was actually very graphic, as pointed out by a number of the speakers before, the issue really gets down into the issues of the air regulations.

Perfect example, we developed the Lopez Canyon Landfill, southern California; 25 megawatts worth of gas. We were only able to site 6 megawatts worth of power. What's happened with the rest? It's being flared.

We're currently being consulted on a large landfill in San Diego County. There's roughly 10.5 megawatts of gas now being flared, 7.5 megawatts of gas that's under internal combustion generation. We could actually make more than 20 megawatts worth of gas if we really processed that gas, put it into a pipeline and transmitted it up the road to an existing generation station that operates far more efficiently than those small internal combustion engines.

So we could use 7000 or 7500 Btu per kilowatt hour heat rate, rather than the 10,500 heat rates that's currently generating power. So we can actually produce more power with it. And we're going to have basically no emissions.

Why can we do gas processing in terms of permitting versus electric power? Gas processing facilities have virtually no emission profile. There is some because you do have to destroy some trace components, but basically you're going to be displacing a flare of that gas in terms of the emissions.

So from a permitting perspective they're far easier to permit than would be electric generation. They have far greater benefits in terms of the ultimate use of the gas for electric power use.

They also have use for the low carbon fuel standard, which we're actually doing in Texas, also, because we're actually going to refill trash trucks on that landfill down there, also. So there's a multitude of benefits that come from this.

The ability to rely on other states, I

think, to get our renewable power like we did in this particular instance here, is going to go away if we have a federal standard adopted, because there's going to be great competition for that.

We've already experienced it with a state that actually doesn't have a renewable portfolio standard. We proposed with Shell the same solution, and we had the Gas Company say no, we don't want to do that. We're going to pay you more for the gas to keep it here.

So I think that it's incumbent on California to utilize all of the resources that it has. Gas processing is going to be at the largest landfill. And from our own personal experience, the landfills we develop, there's a lot of landfill gas today that is just being flared and not utilized.

PRESIDING MEMBER BYRON: Thank you very much, Mr. Williams.

MR. WILLIAMS: Surely.

PRESIDING MEMBER BYRON: Now, wait, before you leave I'm going to ask the staff to comment on the issue that you brought up about the 21-year-old legislation on the vinyl chlorides.

But I'm missing the obvious here

somewhere. Why is it that you're flaring so many potential megawatts of electrical generation?

MR. WILLIAMS: Because you cannot permit, under the air standards, any additional generation. That's the -- there were comments made today where you have --

PRESIDING MEMBER BYRON: Because of the offsets --

MR. WILLIAMS: Yeah, it's clean air versus renewable power. And if you cannot get a permit to site it, there's no generation, the gas gets flared. It's just an excess resource that's wasted.

And that is the conflict between competing, if you will, environmental standards.

PRESIDING MEMBER BYRON: Right.

MR. WILLIAMS: The one for clean air and the other for renewable power.

PRESIDING MEMBER BYRON: Okay, I do understand.

MR. WILLIAMS: So that's the issue.

PRESIDING MEMBER BYRON: Mr. Williams, thank you very much for coming today.

MR. WILLIAMS: Thank you. I left some materials here for you and your staff, as well.

Thank you.

PRESIDING MEMBER BYRON: Oh. All right. There was some things on the podium that did not have a title on them. No, I'm sorry, --

MR. ORTA: I have them up here.

PRESIDING MEMBER BYRON: Okay. I'd like to see them.

MR. ORTA: I'd like to call up Ken Brennan from PG&E.

MR. BRENNAN: Good afternoon. I'll keep my comments fairly brief. I've got a whole list of things to talk about.

I work on biogas projects, biomethane injection projects for PG&E for years. Been working with Dave Warner and Allen Dusault and a number of other people.

We are working on all kinds of projects, not just dairy biogas. Currently working with Mr. Jim Tischer, who's in the audience, from the Center for Irrigation Technology in Fresno on an agricultural based digestion project. So there's a lot going on there.

The comments I'd like to make are mainly relative to landfill gas, pipelines and also to a document that was submitted into docket 09-IEP-1G by Western United Dairymen.

First and foremost, going back to Hayden's law, which I believe was implemented by the CPUC in 1988, in at least the SoCal and PG&E tariffs. That law essentially prohibits, like I said, -- like Mr. Williams said, vinyl chloride from going into the pipelines.

There are a number of other issues that were not discussed today, which need to be brought up. That is the unknown gas quality of whatever the constituents of concern are in the landfill going into our pipelines.

PG&E, as well as SoCalGas, and every other gas utility, we have the single charter on the pipeline side. That is to keep our pipelines and our customers safe from harm. So we have to deliver reliable gas -- and the customers won't get harmed by the gas in their homes or in their equipment.

We don't know what's in landfill gas because of feedstocks going into the landfills are so variable. We don't know what gets dumped in there, what decomposes. So gas quality testing is going to be very tricky, at best. And we have to gain a certain level of comfort that we currently don't have before we can accept that gas.

Back in the '80s I understand there was a project in Mountain View that ate up X miles of pipe for PG&E. We had to replace all that. So we're not against taking that gas at this point, but our tariffs prohibit it. We have to do extensive gas quality testing, as does SoCalGas, before we'd be willing to accept that gas.

And I'll be quite honest with you right now, PG&E's working on a limited number of resource in terms of bodies, and a limited resource in terms of budget dollars for gas quality testing.

We're moving through as many different forms of biomass feedstocks as we can. We've done dairy; we've worked on agricultural products; food waste. And we're moving into other feedstocks after that. Landfill gas is at the end of that road, because it's the most difficult to test for. So we're going for the low-hanging fruit first.

So we can talk more about that offline if you want; I just wanted to get those points in before I move on to my next comments.

There's a document that I was handed out today; I assume it's online, available online, as well, dated April 10, 2009, from Western United Dairymen. Talks about the problems that are experienced with onsite generation in California.

And on page 2 of 3 of that document, in the second paragraph down, there is a quote in there that PG&E wrote the initial contracts for developing these facilities on dairies. It says the economics no longer work as natural gas prices have fallen by nearly half since the first contracts were written.

Since either me or my boss would be the one that made that comment, I'd like to say that PG&E still believes that these projects are economical. We are looking at a number of different revenue streams from these projects for the developer.

There's a commodity price on a forward curve. Currently it's 6, 6.50, whatever. It's not the spot price, it's the forward curve price.

There is a carbon credit value to these projects, as well, which I'm not sure what the market value is in Chicago, but I know PG&E's climate smart program which purchased carbon credits, is currently offering between $7 and $9 or somewhere around there. Again, that's not my program, so I don't know for sure.

Assuming a couple of dollars for greenhouse gas reduction credits, and there's a residue stream for what comes off the dairy digester, you could be looking at anywhere from $16 to $20 a decatherm.

There's a federal tax credit that PG&E and a number of other companies have been active in trying to get through. $4.27 -- Btu gas produced for injection. That's called the biogas production incentive Act of 2009, I believe. That's bill 1158 going through the House and Senate.

So you add all that up together and you're sitting somewhere around $20 a decatherm for this gas. Now, maybe a single dairy may not be economical, but Allen mentioned clustering the dairies. What PG&E calls community digestion.

There are a number of developers out there, Microgy and Bioenergy Solutions, with which PG&E has contracts. They are developing clusters of projects out there. And they're moving forward with these projects, permitting stage, and a number of other business plans.

Bottomline is they wouldn't be doing

this if these projects were not economical in some fashion. It's simple basic math. They're moving forward, therefore there's economics here.

So I would like to disavow the statement, certainly from PG&E's perspective, of what's in that Western United document.

The last thing I would like to say is on the interconnection time and costs that were mentioned by Mr. Sullivan, I know for a fact PG&E's been working on shortening the time for both gas and electric interconnections. And I hope he wasn't talking about PG&E in that comment.

But it's my understanding that great progress has been made, at least in our company, on that.

Those are the comments that I would like to make at this time.

MR. ORTA: Thank you. We only have time for three more comments of roughly three minutes each. I'd like to call Bill Nelson from Sempra.

MR. NELSON: Good afternoon. I wanted to stress that I work for Sempra Generation; we're the IPP of Sempra Energy, not the utility.

Sempra Energy, as you know, is a Fortune 500 company with a market value of $30 billion in assets. We've got a proven track record of project development in both electricity and natural gas.

We currently own and operate 2600 megawatts of combined cycle generation. Rapidly developing additional wind and solar power projects in Arizona, Nevada and in California.

All the products in Sempra Generation's development pipeline are renewable. We're currently pursuing biogas and biomass opportunities throughout the United States, the western United States.

On the bioenergy policy California has an interest in developing bioenergy in California, it must develop targeted incentives and policies rather than rely upon generic renewable energy policy.

Bioenergy may not be cost competitive with other forms of renewable energy at this time. The cobenefits of many types of biomass and biogas production may merit special incentives in order to capture these additional benefits.

Sempra Generation has studied the production of biogas extensively over the past years. Current market does not seem capable of supporting significant levels of biogas production given existing incentives and prices.

In regards to the remarks that were just made, I guess Microgy or for Microgy, I'm not saying anything against the company, but their stock share is 40 cents per share right now. Because of the lack of being able to build projects, cost, profit basis.

As you know, biogas has many cobenefits. These existing policies are not being fully developed. Labor, intensive activity, -- 6 megawatt plant is in the order of 20 jobs. And most of the jobs will be in a high unemployment areas in the central valley.

Significant GHG reduction due to methane capture and use is another benefit that could be used.

The use of renewable biogas at existing generation facilities requires no new transmission, no firming costs, and a non-intermittent resource dispatchable, i.e., no integration costs.

Lack of strong market signal for GHG value significantly undermines the economics of biogas production and deters early action. It leaves potential significant GHG reduction on the table. And current federal incentives require an on-farm generation. Federal PTC does not appear available for off-farm centralized generation.

Sempra Generation is a technology agnostic. We are in the business of developing renewable energy from whatever source makes the most economic sense. Currently our capital is going to wind and solar projects.

Sempra already has excess capital to construct projects that provide adequate returns. So we're not depending on the banks. We can do this, ourselves.

We have a significant internal appetite for tax credits. We do not require access to tax equity market. We will continue to examine the biopower sector seeking economic projects.

That's all I have to say.

MR. ORTA: Mark McDaniel from L.A. County Sanitation District.

MR. McDANIEL: Thank you. A lot of my comments I'll put in writing, involve barriers that have been covered by the other speakers. So I'll talk about a few specific issues.

We operate wastewater treatment plants

and landfills in Los Angeles County. We have 11 power plants and make 128 megawatts. Of that, 88 megawatts is biogas, 40 megawatts waste-to-energy.

Just a note, nuances of regulations and legislature, our 40 megawatts of waste energy does not count as renewable power. Stanislaus' does count. As these projects come off the 30-year utility contracts in a few years, it'll be important for us to be able to keep these plants running to have that renewable power.

We also have 26 megawatts of -- yes?

PRESIDING MEMBER BYRON: If I may, why does yours not count? I missed that.

MR. McDANIEL: By state law, Stanislaus counts as renewable energy. Other waste energy facilities don't.

PRESIDING MEMBER BYRON: Special law?

MR. McDANIEL: Special law, yeah.

(Laughter.)

MR. McDANIEL: And I believe the background is that our facilities did have good contracts in the 1980s and Stanislaus didn't have those contracts.

On our self-generation we make 26 megawatts of self-generation from digester gas and landfill gas. That, in the absence of a promulgative renewable energy credit regulation, we cannot get any economic value for that. Doesn't show up counting toward state's RPS, so we're hoping that that process moves forward so we can bring that renewable power to market.

Cost of microturbines, just as an aside, I also want to mention we have, I think, everything you mentioned here, microturbines, fuel cells, engines, steam boilers, combustion turbines, and the IBPTU project. Microturbines run about $3000 to $4000 per kilowatt, turnkey installation. Gas cleanup is a big part of that. Reliability is okay, not as good as an engine, but it's okay.

And just kind of -- somebody mentioned state agencies at cross-purposes. An example where we have had probably four of our hands tied behind our back are Valencia Wastewater Treatment Plant had a 500 kilowatt engine that was making power for onsite use, generating all the steam we needed. It shut down in January of this year because of the South Coast AQMD rule 1110.2.

We were planning to install new digester gas-fired boilers to make steam. South Coast

AQMD, as you may know, has a permitting moratorium on some offset issues, so we can't put in the new boilers. We can't permit anything with a smoke stack.

Right now we're renting a natural gas-fired boiler to make steam, and flaring all the digester gas, and unable to permit anything at this facility.

MR. ORTA: One more --

PRESIDING MEMBER BYRON: Thank you for your comments. I was not shaking my head in response to your comments, certainly, but the content of your comments is very troubling.

MR. ORTA: I have one more commenter. For those of you who did not get a chance to comment in this period, please, I encourage you to submit your comments in writing. I do apologize for that, but you all eventually want to eat lunch.

The final person I'd like to call up is Edan Prabhu from FlexEnergy.

DR. PRABHU: Good afternoon. I am the barrier between this meeting and the consumption of biomass hour.

(Laughter.)

DR. PRABHU: I am the President of FlexEnergy. What we did is we took a gas turbine and a thermal oxidizer, and we married the two technologies.

And our internal testing shows us today that we are able to achieve NOx well below 1 ppm, VOCs below 1 ppm, and CO below 1 ppm. And so we'd be very happy to talk to you about that.

Thermal oxidizers are used for destruction, and they destroy while they make heat. And we were able to use that.

Our plan is to put these turbines on landfills in the short run. And so several of the subjects discussed today were very very dear to our hearts, and we will provide detailed written comments.

We intend to own the power plants and run them, ourselves, so that there is no excuses as to what the emissions are. We intend to sell electricity.

We have contracts with Southern California Edison for four of those six biomass contracts, for a total of 13 megawatts. One of which is in Kern County and is 4 megawatts, and we plan to get started on that.

One of the advantages of our system, in addition to its low emissions, is that we can handle landfill gas all the way down to 20 percent, 10 percent, 5 percent and even 2 percent energy. So we could stretch the active life of a landfill by at least 30 years. Because you will find today that many many landfill gas plants are running at well below half capacity. And that, we think, is a very serious issue.

The comment on -- brief comments on the utilities, and then brief comments on what we propose to be done.

PRESIDING MEMBER BYRON: You've said only good things so far. Are you sure you want to venture to this area?

(Laughter.)

DR. PRABHU: Biomass, waiting for me, can hold a little longer. We applaud Southern California Edison for its standard contracts. They were extremely easy to get the first signature on. They were a jungle to get the CPUC approval on. It took lawyers and lawyers weeks and weeks.

Relative to interconnection, I headed the group that developed the streamlined interconnection rules. And when we applied for our own interconnection with the local utility, we went into total jam.

This was really difficult because they wanted the power, but their interconnection folks didn't talk to the people who needed the power, and we got stuck with it.

So what I'd like to recommend as a means to address many of these issues, is first, relative to the standard biomass contract. The stunning success of the '90s was the fixed price period for the first ten years that allowed front-end loading, that allowed financing, and produced the finest power plants for renewable energy on the globe, the SEGS and the wind technologies. We should do that now again.

Front-end loading or capital buydowns or something that gives us the first few expensive plants with brand new technologies something to live with.

The second thing I'd like to propose is bring utilities into the fold. If they want the electricity, and it's renewable electricity, let them stand up and pick up the cost of interconnection. Put them in the ratebase, if they need to, because they are adding wires, they are strengthening the grid.

If they become part of the team these long delays, this long confusion, this handing over from hand to hand to hand will slowly start to stop.

We look forward to installing a plant later this year. We will have NOx well below 1 ppm. It will be in Riverside County. We then plan to expand to other areas.

And thank you very much for your time.

PRESIDING MEMBER BYRON: Very good comments, thank you for coming, Dr. Prabhu.

MR. ORTA: That's all the comments that I have. Anyone else, please submit your comments in writing by May 5th.

We do -- right now we are almost an hour behind schedule. But I think we still have enough time to take lunch for an hour, and I'll ask other speakers to cut their presentations.

PRESIDING MEMBER BYRON: Okay. I don't -- according to your schedule, lunch break is at 12:20. So, we're about a half hour behind schedule. And because this is so well attended and the comments are excellent, this Commissioner will stay here until as long as we need to, to make sure everyone's comments are heard and on the record.

So we will not be cutting the program short, but we will, of course, continue with the presentations.

So, we'll be back here -- let's really try and keep it to an hour, so let's be back here and start at five minutes to two. Okay. Thank you.

MR. ORTA: Thank you.

(Whereupon, at 12:52 p.m., the Committee workshop was adjourned, to reconvene at 1:55 p.m., this same day.)

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AFTERNOON SESSION

1:57 p.m.

MR. ORTA: The Commissioners have returned from lunch. They're on the dais. After a very productive conversation this morning about where we are with the RPS and where we could be going, and also a very interesting set of presentations on biogas and some comments on that, we'd like to shift gears a little bit and talk about solid fuel biomass issues.

We have a set of four speakers that will talk about state of the biomass industry. Also feedstock potential from landfills and forests. We'll have speakers from the California Department of Forestry and the U.S. Forest Service.

Commissioner Byron, this morning, informed us that we'll be here as long as it takes. And so we're all very interested in your comments, and won't be rushing you as much this time around.

Our first speaker is Greg Morris from the Green Power Institute.

MR. MORRIS: Thank you, Commissioners and thank you, everybody, for having me here. Commissioner Byron giving me carte blanche on time may be a major mistake, but I'll --

(Laughter.)

MR. MORRIS: -- do my best.

PRESIDING MEMBER BYRON: I saw that you had a wardrobe consultant there, who was helping you with your suit earlier.

MR. MORRIS: I'd like to talk a little bit today about the current state of the biomass industry in California. And partly inspired by the fact that I have developed and maintained a database on biomass power use in California. I guess the original database was started around 1990, and has been updated every two years. And it was updated in 2008, and with 100 percent participation of all the biomass, solid fuel biomass that is, generators.

So, we're really here today inspired by the executive order S-0606, which says that biomass should be 20 percent of the RPS. And I noticed this morning we were a little bit proud of the fact that, in fact, biomass is 20 percent of the RPS. But it's important to keep in mind that the reason that the executive order puts us at 20 percent was because that was the baseline. And the idea was to maintain that baseline as the overall renewables in the state grew.

And so, yes, in 2008 we have 20 percent biomass and biogas together. But when you look at the portfolio of new projects under development that the various utilities have in California, you'll notice that there's virtually no new biomass. There's a couple of restarts. And very little biogas.

So that the only reason that we've actually maintained 20 percent biomass within the context of the RPS since we started in about '03, is because the overall amount of renewables hasn't changed much. And neither has biomass. And so the others haven't grown past it. But if the others do grow past it, as many hope that we will actually make progress on the RPS at some point, that biomass is likely to be looking at a smaller and smaller piece of that pie unless something is done to promote biomass as a specific policy option.

But what about the overall RPS? The RPS, itself, is having a great deal of trouble making real significant progress on the ground. So I have made this slide up that shows in the red line what the annual procurement target for -- and this is just for the three large investor-owned utilities in California, the red line shows what the annual procurement target has been for those three in aggregate. And the dark blue line shows what the actual procurement has been.

And as you can see, between 2004 and 2007 the actual procurement of renewables in California by those three large IOUs, and they procure almost all of the renewables, has actually gone down every year from 2004 to 2007. And it went up just a little bit in 2008. This, again, as a percentage of total retail sales. But the increase in 2008 was still below the minimum 1 percent incremental procurement target.

So even though we had a little bit of an increase in terms of the RPS percentage in 2008, we actually fell further behind in the actual attainment of our procurement targets.

And I then show in the sort of pink line what the IOUs, themselves, are projecting for the next three years, '09 through '11. And I also, because my experience with the IOU projections has been that they've always projected more than they've actually received, they've assumed every new facility will come online on time. And these projections it appears to me to assume a pretty good hydro year for '09, which I'm a little surprised about.

So I also show some lower rates of success with the new projects. The green line shows only 70 percent of the incremental new RPS capacity that the utilities projected. And the lighter blue line shows 50 percent of the new.

But in any case, even if you take the pink projection you see that the utilities are not getting close to 20 percent anytime soon. Their own projections, and their optimistic projections puts them at about 16.5 percent in 2011.

And yet these utilities are still talking about making it by 2013. But if you project that pink line out there you're not close to 20 percent in 2013.

And, in fact, I've looked at what would it take to bring us to the 33 percent by 2020 that is, you know, state policy and likely to become statutorily required in the state, and you can see that the sort of shaded red line is a scenario that I put together to show what it would take to get to 33 percent using normal market forces over that time period.

And you can see that we will have to do a huge amount of growth of new renewables during that period of, you know, 2010 to 2016, let's say, way beyond anything that we've accomplished so far.

And I actually believe it is do-able, but it is not do-able if we continue down the course that we've been on. But that's the overall RPS, and we're really here to talk about biomass today.

So, why do we care about biomass so much? Well, biomass, which we know is somewhat expensive compared to the other renewables, still provides a whole set of waste disposal services that are unique in the renewable area, okay. So it's not just the renewable energy that you get with biomass, it's also the waste treatment, you're reducing conventional pollutants. But perhaps most significantly you're reducing biogenic greenhouse gases.

So let's talk about the carbon cycle and biomass and carbon neutrality, because that's a very important issue as we move into the AB-32 world.

The biomass that's within that green box is what we call biogenic carbon. It's the carbon that is in rapid exchange between the atmosphere and the biosphere every year. And that's what biomass carbon is. It's different in a fundamental way than fossil carbon, which is carbon that is inaccessible to the atmosphere unless we actually dig it out of the ground.

So, there's actually, you know, according to these numbers, 15, 16 times more carbon exchange between the atmosphere and the biosphere every year than there is fossil carbon being moved into the biosphere and the atmosphere. But the difference is that using biomass carbon is using carbon that's already part of that cycle, and it's not increasing the carbon in the cycle.

Using fossil carbon is putting new carbon into that whole system. And it comes out very very slowly.

So, but biomass is much more interesting than just saying, well, if it's biogenic therefore it's carbon neutral. Actually it's not necessarily carbon neutral. And sometimes it's much better than carbon neutral.

But certainly we have the stock of carbon in the atmosphere. We have the stock in the biosphere. And we can push those two stocks in either direction depending on what we're doing.

So, certainly if we improve the forest and we are able to therefore have a higher stocking of carbon in the forest, that carbon comes at the expense of the atmosphere. So there's some room for actually scavenging carbon from the atmosphere by healthier forests.

But, also important is the fact that when biomass carbon goes back to the atmosphere, as it inevitably does, it goes back in two fundamentally different forms, oxidized and reduced. Oxidized being CO_2, and reduced being methane or any number of hydrocarbons, but from a climate perspective it's basically two things.

And methane is 25 times more potent as a greenhouse gas than CO_2. Although it has a much shorter residence time. But, of course, what happens to the methane when it clears from the atmosphere? It oxidizes as CO_2.

So you have two different ways in which biomass, biogenic carbon can actually be reduced as an atmospheric burden by the use of biomass energy systems. You could have healthier forests and you can also affect that ratio of oxidized to reduce carbon coming out of the biomass degradation.

So there's a great potential there for reducing greenhouse gases in association with biomass.

The biomass industry in California has been operating since approximately 1980. And this graph shows two lines. In brown I'm showing the avoided fossil emissions attributable to the production of energy from biomass.

And every year since 1980 we've avoided carbon dioxide emissions from coal and gas. And this goes up through operating year 1986. And so then I'm just showing beyond '86 -- pardon me, not '86, but 2006, I'm just showing the slow clearing of CO2 from the atmosphere from that CO2 that we avoided, but had it been there it would have done that clearing.

But in addition to that you have the green line which is strictly the biogenic carbon. Biogenic carbon actually increased in its atmosphere component for the first almost ten years of the industry's operation.

That's a function of, for example, burying a lot of that in landfills where it does emit, but not immediately. So you delay those emissions and that's part of what's going on here.

And, of course, when you thin a forest you're actually cutting down biomass and burning it, and making immediate CO2 emissions. Although in the long run you're promoting forest growth; you're preventing the destructive wildfires. And so in the long term you actually end up sequestering much more carbon in the atmosphere because of those forestry activities.

So, the biogenic carbon effect in terms of reduced greenhouse gases is kind of comparable to the avoided fossil carbon effect in California. If you looked at a similar graph in the midwest you'd see the fossil being much greater because they're primarily coal, where we're primarily gas.

But here in California's situation it just so happens that the two give you roughly equal effects, which is another way of saying that biomass gives you twice the greenhouse gas benefit of a strictly carbon, noncarbon renewable like gas -- pardon me, like solar or wind. So it's a pretty compelling story if we can make it happen.

So let me quickly go through where is the biomass industry in California today, because there's a lot of misunderstandings at times about where we are.

First, here's the map of biomass plants. We have, I believe, 31 operating right now. This update was done in mid-2008, so a couple of those blue dots which are plant restarts of existing facilities have, in fact, restarted. And a couple of them probably won't restart. But otherwise this is pretty accurate.

And you can see that we've lost a lot of plants. We actually have gone through about 60 or 62 plants in the state, of which about half are currently operating.

And so what has happened to the capacity? We often talk about the fact that we're losing biomass capacity in California. Well, there have been times when we have certainly lost biomass capacity in California.

But the last few years, the 2000s, it's been somewhat steady. We had some restarts inspired by the energy crisis of 2000/2001. And there were some other contractual reasons why a couple other plants restarted, as well.

There was a slow decline as things stabilized again, but most recently, with the great pressure on the utilities to try and achieve RPS goals, they have managed to restart a couple of the existing facilities.

Although I will say that the big addition of capacity shown here in 2009 is based on a mid-2008 projection by these various facilities. And I'm pretty sure that some of those won't, in fact, happen. So I think the very tail end of that upswing will not be as dramatic as what's shown in the graph here.

And this graph shows sort of at what operating profile the industry is operating at. And in effect, if you look at the bars on this chart, the bigger the blue section of the bar in the top the actually less capacity factor that the industry, as a whole, achieved in those years.

And, again, it's interesting that you can see that they were projecting in mid 2008 that they would be running almost flat out as an industry in 2009. I doubt if that will actually hold up. I think you'll see a little, as we redo this in a couple year s, you'll see a bigger blue space on the top of that. And the whole bar will be a little lower, because some of that capacity won't have restarted.

The fuel price in California is, as a statewide average, is shown in the red curve. And then the southern California fuel prices is in the purple. It's actually quite a bit less than the northern California fuel price in green.

Part of that is an outcome of the fact that when we had shutdowns of the industry we shut down more in the south, as a percentage of the capacity, than we did in the north. And part of that is the fact that the northern plants tend to be more dependent on forest fuels, and forest fuels are more expensive, just by their nature.

And this slide shows how the four sort of basic different types of solid fuel biomass in the state have fared over the years. We certainly started out as an industry primarily based on the use of mill residues. And we still do use basically all mill residues in California that don't have any higher valued purpose.

But nonetheless, those mill residues, as a quantity, have been going down every year, and that's simply tracking the lumber industry, itself.

The biggest replacement fuel as mill residues have receded, has been the urban residues. And that's partly an outcome of AB-939, the solid waste diversion bill. And partly just a matter that material tends to be a little bit less expensive. But, again, part of the reason why it's less expensive may be related to the need for the landfills to not bury it.

And we also use ag residues and forest residues.

MS. BROWN: Greg, can I ask a question on your prior slide. When you talk about fuel prices, you're really talking about the cost of the biomass fuel to the producer?

MR. MORRIS: I'm talking about the delivered cost that the producer pays.

MS. BROWN: The delivered cost. I think of it as a cost, not price, so that's why I wanted to clarify. It's the cost paid by a producer for the fuel.

MR. MORRIS: Yes, I -- yes, the survey's based on the power plants. So it's their cost of acquisition, and we don't try and value the fuels that are captive fuels at plants.

And this shows now the prices of these different kinds of fuels. And you can see that the urban fuels have been the cheapest over the past few years. And certainly the forest fuels are the most expensive. They're now averaging greater than $50 a bone dry ton.

Interestingly enough the mill residues, which tend to be on the lower side of cost to produce, have been able to earn a premium for the people who produce those residues, because they're in that area where fuel prices are high. So there's a little economic red in that blue ribbon.

And this shows the California biomass fuel supply curve as it has existed now for 20-plus years. And it's been quite remarkable how consistent we have stayed close to this curve. And it actually is a great vindication for basic micro-economics 101. Sometimes it even works.

But unfortunately, the lesson for us here is we think about how to try and grow this industry, is that the more solid biomass fuel we want to use in the state, the highest the average cost will be.

And it's a simple phenomenon. Obviously the facilities try to procure the cheapest fuel they can. As they have to procure more fuel above what they're already using, they're going to have to go further, more into higher cost supply situations. And that's true of a single facility on its own, and it's true of the industry in aggregate.

So when we talk about growing biomass we have to be aware that our overall average fuel cost will be affected by that, unless we have some policy instruments in there to try to and counteract that phenomenon.

And fuel is really important to us all. A fuel biomass power plant, it's typically anywhere from 40 to 60 percent of their total cost of operation.

So, this tracks a little bit of the trend of what's been happening. We've lost some of our sawmill CHP units, so that the amount of behind-the-meter use of electricity has gone down. Again, a lot of that's in the milling industry; a couple of food processors in there, too.

And the electrical surplus sales, or for most facilities, all their sales go into the grid. And that's gone up and down with the number of facilities and other economic conditions.

So, to sort of conclude here, my opinion, of course, renewables need a jump-start. We've been remarkably stuck where we are, about 13 to 14 percent for the three big IOUs. And because they're the major procurers of renewables in the state, that translates to about 10 to 11 percent overall for the whole state in terms of renewable content. And it really hasn't moved much.

So, I would advocate for, and certainly there's a lot of work going on right now in the Legislature with all the agencies contributing to trying to reform the RPS, to try and find ways to make it work better. Right now some will tout its great success at landing new contracts, but nobody's going to tout its great success in landing new operating megawatts. That's been very modest and not really kept up with load growth in the state.

And I don't know, the utilities, as I recently filed a paper on this issue, said, well, wait a minute, we got an economic downturn, so demand's gone down. So if we just keep the renewables we have we'll see the renewable percentage go up.

Well, that's true in the short term. But we all hope that the economic downturn is not going to extend too far. And we'd like to get back into an obvious healthy situation.

So we need to reform the RPS. And we believe that we need to get rid of the MPR, which has been a real impediment to development. The utilities have complained tremendously that the RPS is creating a floor price for renewables. And, yet, they continue to tout the benefits of the competitive marketplace.

But if the competitive marketplace is being compromised by an RPS which is setting the target price, then it's not working anyway. And we need to find ways of making that work, either as a competitive marketplace, or by using standard tariffs, or by doing something that will bring us beyond simply writing a lot of contracts that aren't being fulfilled to the point where we are fulfilling our contracts. Because that's what really matters.

Renewables are carbon neutral with the one possible exception of those that cofire fossil fuel. But aside from the cofired fossil fuel, we all know that renewables are carbon neutral. And they really ought to be exempt from cap-and-trade. That hasn't happened yet, but final determinations aren't made yet at the ARB.

But we certainly hope -- I certainly

hope that we can get an exemption for renewables in general, except for their use with fossil fuel, from the cap-and-trade systems so that they are then eligible to be generators of offsets, should they, in fact, have a legitimate claim to making offsets. And I believe that both biomass and biogas do make offsets.

And they need to be exempt from that cap-and-trade system in order to generate offsets that they can use. And those offsets could become the vehicle for making or allowing biomass and biogas to grow, even though they're not the lowest cost renewables.

So I certainly hope that we can get to that point, and that those greenhouse gas offsets can provide the incentive that we're looking for. Because we haven't found a way to do it so far.

And they provide other benefits, as well, but those other benefits like reduced conventional pollution, reduced landfill loading, healthier forests, while we all recognize them, we haven't yet figured out how to make them actually benefit the biomass industry.

And if the biomass industry doesn't benefit by generating those benefits, then we won't get the benefits because the biomass industry won't thrive.

So, thank you very much.

ASSOCIATE MEMBER BOYD: Thanks, Greg. Always good comments.

MR. ORTA: Our next speaker is Fernando Berton from the California Integrated Waste Management Board.

MR. BERTON: Good afternoon. I'm delighted to be here. I'm Fernando Berton with the Waste Board. I'm the manager of the research and applied technology branch. And what I'd like to talk to you about today are some board policies and activities that we have for diverting biomass from the wastestream. Give you a little bit of background on what we've done. And then some of the challenges and opportunities that we have.

As you can see, we do have various policy drivers, the first and foremost being the Integrated Waste Management Act, which is basically AB-939, that set forth goals for landfill diversion that local jurisdictions must achieve 50 percent by 2000.

And in February of 2007 the board also adopted some strategic directives, and just recently they revised those strategic directives. As you can see, strategic directive two, our vision actually, when it was revised, to include a clause of enhancing bioenergy and biofuel production. And so that aspect is very important as part of the board's vision.

Strategic directive 6.1 deals specifically with organics and a goal of reducing and moving 50 percent of organics out of the landfills by 2020.

In order to do that we also have to look at our existing regulations, so strategic directive 8.4 is designed to look at our existing regulations and revise them, taking into consideration the science behind new technologies.

Which kind of flows into strategic directive 9.0, research and development of new technologies. And I'll touch on these -- on different aspects of these as I go along.

To give you an idea, back in 1990 our diversion rate was just over 10 percent. This is sort of a good news/bad news slide. The good news is that we've gotten up to 15 percent now. So, statewide, we're well above the 50 percent goal.

This takes also into consideration our

population growth as you can see from this growth curve, or growth line. It's sort of a red-colored line.

Unfortunately, the materials being disposed of in landfills has not decreased at the same time that our diversion has increased. And a lot of this is because of the population growth. We basically have been able to divert our population growth.

Another aspect that we are looking at is the per capita disposal, pounds per person. And it hasn't really dropped significantly, either. It's pretty much flat-lined.

This is important because a bill that was passed last year, Senate Bill 1016, changes the way that we look at the -- we no longer actually calculate diversion. We're looking at, it's a per capita disposal reduction.

So jurisdictions now, instead of us calculating diversion, we're going to be looking at disposal reduction.

So what's important here is that in terms of biomass credit in the past there was a 10 percent credit for biomass. Under this new law, new scheme of things, Senate Bill 1016, there is no specified diversion credit under Senate Bill 1016.

So, materials diverted from a disposal facility to a biomass facility would result in a disposal reduction. So anything going to biomass would be calculated as part of the disposal reduction. So we see that as a positive aspect.

So, you know, either way, you know, we're still making strides.

I'd like to point this out and use this slide because this shows the kind of urban footprint and projecting into the future. Looking at 1998 and 2020 you see some growth in various parts of California, mostly like the Inland Empire, and long the highway 99 corridor.

If you move forward, it's projected that the Coachella Valley and also farther on down the highway 99 corridor and the Inland Empire will really grow. So basically, you know, you've got more people, you have more houses. So you need more electricity, you need more baseload power.

So, we need to, you know, have new sources of electricity. Of course, with the economic downturn who knows what the projections will be like if they would, you know, revise these or not. But I think in the long term, economic downturns are small blips in the grander scheme of things.

Looking at our waste characterization in California, you know, we dispose of anywhere between 39- and 42-million tons in a given year. A lot of it depends on the economic cycle.

Of that amount 23- to 25-million tons is biological in origin, depending on how you slices the pie. So, we have a lot of material that has energy potential that's being buried.

So, you know, if you look at the paper and the cardboard, that's some 20 percent; food is about 15 percent that's still being disposed of.

This is data from our last waste characterization study which was done, I think, 2003, 2004. We're in the process of conducting, or will be conducting another waste characterization in the not-too-distant future.

The other thing, the California Biomass Collaborative and UC Davis and the staff there did an analysis for us in preparation for a workshop that we're going to be conducting on biofuels and biopower.

And what this analysis showed is that

the biomass fraction being landfill again was about 25, almost 26 million tons. And if you look at the electricity potential, that's about 1750 megawatts. So that's a lot, again, a lot of power being buried that if it's diverted from landfills could be made into electrons. So, hence it's a priority for the board.

If you look at it from a mass-versus-energy distribution, again you can see that paper and cardboard is the largest fraction that's being disposed of; and also has a fair amount of primary energy potential.

Looking at film plastic, although film plastic isn't, you know, necessarily considered biomass, you know, it has greater energy potential per mass unit.

What's interesting here is the food. You look at the food waste, there's a lot of energy potential. And food waste, of course, is still 15 to 16 percent what's being disposed of.

So that's one of the big targets that local jurisdictions are looking at to not only achieve a greater diversion rate, or actually disposal reduction -- I'm still trying to get out of the mindset of diversion rate -- but also looking at, you know, food as potential energy sources.

So, again, you know, from the analysis by the Collaborative, all this material that's being disposed of is equivalent to about 67 million barrels of crude oil, or, you know, about 2600 megawatts of electricity.

Back in 2007 we held several summits and we developed a policy roadmap. And part of that roadmap was addressed -- was designed to address six key areas that came about as areas of concern in the organic summit that the we had and the bio -- forum that we held in 2007.

And those areas were issues dealing with alternative daily cover; economic incentives and disincentives; siting and capacity; regulatory and permitting issues, et cetera.

I think for me one of the big issues also is education. It's an ongoing thing that we have to educate folks.

Specifically with strategic directive 6.1 this calls for reducing the amount of organics in the wastestream by 50 percent by 2020. So it addresses the largest fraction of material still being landfilled.

In terms of the economic incentives and disincentives, what some of the stakeholders told us is that we need to coordinate with other agencies to create effective incentives. And to see how we can get rid of disincentives that address core issues.

We do plan on holding a workshop sometime in June of 2009 to collect additional stakeholder input and some recommendations. And if you're interested in that workshop you can see me afterwards, or I have some contact information at the end of this presentation that you can email me and I can put you in contact with a staff person dealing with that.

Listening to Greg's slides here, his presentation, I think there's some good fodder for some incentives that we can move forward on.

We also have siting capacity issues to deal with. We did an online survey and interviews of local governments to try and identify what the siting barriers were and what the solutions were.

We held some workshops back in April of 2008, and by and large what came about was there needs to be more coordination between the air and water regulatory agencies.

We've got various green missions colliding, where we want to defer materials and landfills, and have it converted to biofuels or bioenergy, but you got criteria pollutant issues to deal with at the local air quality management district.

If you move into compost you have, or even to anaerobic digestion, you might have some issues dealing with effluent and effluent management.

So, we need to reconcile and understand that as we move forward on our issues, we can't move forward in our own little silo. We have to be cognizant of what the other agencies missions are, as well. And I would hope that those other agencies would follow suit.

The other thing that came about was the need for a clearinghouse, a web-based information clearinghouse that local jurisdictions could look to for ideas on things. And legislation requiring diversion capacity.

AB-939 required that local jurisdictions showed a 15-year disposal capacity. But there was nothing in the law that required that jurisdiction to show what kind of diversion capacity that they had.

And so, you know, as you move forward on that, we need to -- we're trying to address those issues.

Let's see, what else. We're also in the process of conducting a comprehensive inventory of California's solid waste handling diversion and market structure. Because, you know, we kind of figured out we're collecting all this stuff, but where's it going. We need to have a better handle where all this material is going.

Especially with the decline in the recycling markets, it kind of brought us to think about, well, what about the organics. So, we're doing a comprehensive survey and study on our existing infrastructure and the needs for additional infrastructure as we try and move all this material out of landfills for either more recycling, more composting or more bioenergy reduction.

As I mentioned in strategic directive 8.4 dealing with enforcement and permitting, this is designed so that the regulations are grounded in the best available science, and to address market conditions, and to take advantage of developing technologies.

One thing that we've noticed is that our regulations have not really kept pace with technological innovation. So it's basically an antiquated set of regulations. So we're trying to basically force-fit some of these technologies into categories that frankly, are not addressed in some of our regulations. So we're trying to deal with that.

And I'm going to talk about one specifically in general along with anaerobic digestion in just a bit.

Strategic directive 9 deals with research and development of technology. You know, strategic directive 0.1 is to develop a focused process to coordinate research. Our research in the past has been more opportunistic. Hasn't really been coordinated.

The funding that we have is sort of a feast or famine. I don't think we're going to have much funding in the coming fiscal year because of the downturn in the economy and less revenue coming into the Integrated Waste Management account.

Strategic directive 9.2 deals

specifically again with the development of alternative energy and biofuels. And this is designed to address the issues in the Governor's executive order S-0606.

And obviously playing an active role in the bioenergy interagency working group is sort of a mainstay that we will continued to do. And then we're active participants in the Climate Action Team.

Now some of the things that we're doing now is we're in the process of conducting a lifecycle and economic analysis of organic materials. We've contracted with Research Triangle Institute to look at the lifecycle benefits of different pathways for organic materials management.

And specifically for organic materials, biodegradable organics. Because what we found is that some of the existing lifecycle tools are good for your typical recyclables, such as bottles and cans, but they're not so good on biodegradable materials.

So the lifecycle and economic analysis is designed to bolster that end of things so that we can see what the GHG benefits are, greenhouse gas benefits are, of composting or anaerobic digestion compared to landfill, which is the basecase scenario.

We also have partnered with the Energy Commission and UC San Diego for the biofuels contract, looking at for us post -- residuals for gasification to mixed alcohols. So, again, looking at what technologies we could use to move organic materials out of landfills into somewhere else.

I mean it's one thing is great to maybe you have a landfill ban of organics. But it's another thing, if you do have a ban, which certainly we're not suggesting, but if there is a ban, where does this stuff go.

So, in the past, some stakeholders have said, no ban without a plan. So we're trying to come up with some potential pathways if there is some movement in the future.

We've also funded, along again with the Energy Commission, a study on the two-stage anaerobic digestion project over at UC Davis. And we're working with the California Energy -- I'm sorry, the Air Resources Board on the low carbon fuel standard so that there's a fuel pathway for low carbon fuel from anaerobic digestion.

Right now there is a fuel pathway for landfill gas to CNG. But there isn't one for anaerobic digestion. So we're working with the Air Board on that aspect. And we've seen some positive signals in that aspect.

We've also submitted comments to the Energy Commission on the feed-in tariff, and to include, you know, or at least looking at alternative technologies in the feed-in tariff.

And then one thing specifically I want to talk about is the anaerobic digestion programmatic EIR. This would be done in support of our strategic directive 6.1.

We've issued an RFP that would -- and proposals are due today, actually -- to develop a programmatic EIR for anaerobic digestion technologies.

These would be -- the facilities that would be addressed would be, in this programmatic EIR, would be either stand-alone anaerobic digesters, receiving solid waste; or digesters that are co-located at landfills.

So it would address the potential environmental impacts from these types of facilities. And so we would hope that the contractor that is ultimately selected would analyze those potential impacts.

And, so, you know, these analyses would be utilized in identifying, defining and ultimately determining the universal level of environmental impacts from anaerobic digestion facilities operating within California.

So we feel that a programmatic EIR might push anaerobic digestion because at this point that's kind of the path of least resistance forward. And could provide that pathway for more organics out of the landfill into an alternative for energy production.

Now, a little bit about challenges. I always like to talk about the product versus the process. I've been to a number of these workshops here and internationally where everybody likes the product, but nobody likes the process to get there.

They like the electricity, they like the renewable electricity, they like the renewable fuels, but they don't like the technologies to get there, you know, and it's tough to get one without the other.

So, you know, I think part of this is, you know, there's a lot of trepidation to these kinds of technologies, mostly I think due to misperceptions of what these technologies are.

A number of stakeholders that are worried about these technologies feel that some of these technologies are incinerators in disguise. Because they would take material that perhaps could be recycled and made into something else.

Well, the target -- and our board has been very consistent in saying that the targeted material is that material which is destined for landfills, anyway, where all recycled materials have been pulled out. So it's stuff that's going to be landfilled anyway.

And if you look at materials, the organic materials that are still being landfilled, some may argue that that material is still a compostable material.

Well, if you've seen the stuff that I've seen, that's post -- and it's composted, I would not want to put that stuff on my garden. It's not good stuff. So, you know, when I talk about product versus process I think a lot of it is misperception.

There are also some statutory updates. It's funny, statutory updates in the sense that there are some definitions that maybe shouldn't be here, and regulatory updates in the sense that there are definitions that are not there that perhaps should be there.

As an example, the definition of gasification in the Public Resources Code was put into the code in something like 2003 with Assembly Bill 2770. We've been trying since 2008 to modify that definition so it's scientifically correct. And we're still here in 2009, actually that definition was actually 2003, so we started in 2004. So it's been a long road to try and update a definition so that's scientifically correct.

The bottomline on statutory and regulatory updates, again it's the issue of antiquated law and fitting new technologies into these antiquated laws. And that's the challenge that we're facing right now.

Well, as far as opportunities, there's plenty of feedstock available. At least from our perspective on the biomass fraction of solid waste. Again, there's some 23- to 25-million tons available that's still being landfilled, depending on how you slice the pie.

So, it's just a matter of making sure that that feedstock is moved in the right direction, however you define right.

The other good opportunity is that, and I think positive direction, is that jurisdictions are moving forward in spite of all the stuff. Jurisdictions like the city of Los Angeles, Los Angeles County, they're moving forward on some of these technologies because they have issues to deal with that are more immediate than what perhaps statute can deal with with these changes.

Puente Hills Landfill is going to be closing in 2013. That's 13,500 tons per day that needs to find a home. Some of that will be rail-hauled to a desert landfill. Maybe that's half of it. So what happens to the other half? So Los Angeles County is looking at alternatives.

Again, same thing with City of Los Angeles. Other jurisdictions are looking at these kinds of technologies, the City and County of Santa Barbara, the Salinas Valley Waste Management Authority, and the City of San Jose.

So, you know, we still have a long row to hoe, but I'm feeling young and chipper and we'll be here for the long road. I don't plan on retiring anytime soon. I would like at least one of these facilities to be sited while I'm still on this earth.

(Laughter.)

MR. BERTON: Instead of burying me, maybe they can process me through the gasification or through the -- facility. So, now with that morbid thought I think I'll end and thank you. And entertain any questions that you may have.

ASSOCIATE MEMBER BOYD: Having heard Fernando's last will and testament --

(Laughter.)

ASSOCIATE MEMBER BOYD: Fernando, I'm going to say something that's nothing new to you, but I just feel compelled to say it. Your no ban without a plan just kind of capped the thinking I had as you talked throughout your presentation of the Swedish model, where there is an organics ban.

Folks there, first they set aside all their recyclables, and then they deposit all remaining materials in their homes and -- and what-have-you in white or black bags. The organics go in one, the nonorganics go in the other, I don't remember which goes in which color.

The garbage truck -- you put them in your can, the garbage truck picks it up. They take it to the equivalent, I guess, of a murf, where the bags are optically scanned. And organics all head out for biodigesters, a shredder. And the other bags, I believe the black bags, go into giant bins that are carted away to MSW plants that generate electricity.

I know that's a no-no in this country, but they seem to have it down. So they've addressed the issue quite well, and they use all organics and other materials for biomethane, in effect, as we heard earlier in the day. They have to import their methane from the Danish, even though they're very civilized people, they don't like importing their gas from the Danes. So they want to get independent of that.

In any event, there is a model. And there are more like that in Europe. And I'm just hoping in your working lifetime we get closure for that. Thank you.

MR. BERTON: Thank you very much.

MS. BROWN: Can I ask you one thing. The legislation you referenced, Fernando, SB-1016?

MR. BERTON: Yes.

MS. BROWN: It seems that the thrust is to divert the waste before they reach the landfill, which one would assume would then free up more fuel for the biomass producers, is that your take? Does that help?

MR. BERTON: That's my take on it, yeah. But I'm certainly no expert on SB-1016. I stay out of that side intentionally, but that's -- yeah, I mean I think I would agree with that.

MS. BROWN: Doesn't address the economics, but at least provides more fuel.

MR. BERTON: Um-hum. One thing to keep in mind on the per capita disposal, I believe the way we look at per capita disposal includes the commercial sector. So there might be an artificial dip in the per capita because of the economic downturn, because there might be less commercial waste that's being generated. So it might actually look like a cliff.

But that could be, you know, a short-term anomaly given the grander scheme over years.

MS. BROWN: Do you feel that the Waste Board has enough authority to achieve this 50 percent diversion goal?

MR. BERTON: Well, yeah. We're working

on a commercial recycling issue right now, and trying to get commercial recycling mandated. So that's still an issue that we have to deal with on the commercial recycling side.

And we see that as a next step to get increased diversion -- well, less disposal -- or more disposal reduction.

MS. BROWN: I guess my last question is has there been any change in the policy on alternative daily cover?

MR. BERTON: No, because that's a statutory policy. And, you know, that would require a statutory change.

We have seen a drop in the amount of material being, at least green material being used as alternative daily cover over the last couple of years. It's still above 2 million tons, but it's less.

So it's heading down. And there might be less that's used as some landfills close. Puente Hills could, you know, could show a huge drop.

Thank you.

MR. ORTA: Thanks, Fernando. Our next speaker is Doug Wickizer from the California

Department of Forestry.

MR. WICKIZER: Commissioners -- Commissioner Byron, excuse me --

PRESIDING MEMBER BYRON: Commissioner Boyd will be back.

MR. WICKIZER: Ms. Brown and Ms. Chew, I'm Doug Wickizer; I'm with the California Department of Forestry, and one of the usual suspects in this room.

Thank you for the opportunity to give you some of our thoughts on barriers to biomass feedstocks. I'm going to speak to three general areas, two relatively quickly and one in a little more depth.

A quick touch on how we get to what a reliable supply would mean to us, both from the aspect of gross biomass that's out there, and then what's technically available to us.

The question always comes up on permitting. How does it affect removal of forest biomass or the management thereof; and what's the cost of that.

And then finally, in response to something that we agreed to with the Commission during the bioenergy interagency work group --

Susan, is that --

MS. BROWN: That's close enough.

MR. WICKIZER: Okay. We had committed to do some additional review on harvesting equipment and potential to reduce costs on that. To try to bring the costs of forest biomass a little closer to some of those others that Greg reviewed earlier.

Reliable supply of biomass, when we started with the Commission a number of years ago, the estimates were all over the map. And the Commission and ourselves have put quite a bit of effort into trying to get a better handle on what that inventory looks like. And a great deal of that work has been done by the California Biomass Collaborative on behalf of the Commission.

The numbers vary because there's different assumptions used in each of the inventories you find out there, from WGA to the Forest Service, to the ones we use in our fire and resource assessment program.

They're based on different geographic scales. And most of them, however, do have a commonality, and that is that they start with the U.S. Forest Service forest inventory analysis.

It's a common database used across the U.S. to present inventories of forest resources.

California Biomass Collaborative estimate is the one we choose to work with because we believe it's the most conservative, and therefore probably the safest to use.

We believe it's conservative because we worked with the Collaborative on that, and they used some of our numbers. We excluded a number of areas that could be sensitive.

For example, forest reserves, and that includes reserves on U.S. Forest Service lands, stream management zones on national forest lands. The estimates do not include biomass on slopes greater than 35 percent where timber can be managed. And then it does not include lands greater than 30 percent on slopes on private forest lands.

Forestry biomass is about 32 percent of the gross 83 million tons available out there. And 43 percent of the technically available.

Just a quick thing on the landbase. I think you can see that we're dealing roughly with 16 million acres. And I do want you to note that the national forests are a big chunk of that, 53 percent of that opportunity that's out there.

California Collaborative, again I just flash that chart up there. It's out of the Collaborative's report, which you have available to you.

Just a quick breakdown. You'll see that the logging slash is about 8 million tons. The forest thinnings are about 7.6 million. The mill residue which Mr. Morris reported is pretty well used up, and we agree to 6 million tons. And the chaparral, which we haven't really started to approach, is 5 million tons. These are annual numbers available over time. I don't want to use the term sustainable yet in this case.

However, the first two, logging slash and forest thinnings, are not close to fully utilized yet. I believe it's somewhere around 2 million tons that have been fed into the bioenergy system thus far.

Just to give you a real quick overview, I mentioned the forest inventory analysis program. One of the reports that they put out is just an idea of what the overall mass is out there. And I just thought it would be interesting to see how it breaks down between all biomass, how that breaks down into live. It's the biggest chunk. The boles is the next biggest chunk.

But if you look at the tops and the saplings, which come from those smaller, more select treatments, and the salvage of the slash after a timber harvesting operation, you're seeing fully over a third of that. So it's quite a bit of it is available without actually using the boles of the trees, themselves.

The barriers on supply. I'm only going, I only put one -- two items here on this slide, but I'll mention a couple of others. Very strong importance, I think, to the state right now, if we're really going to move forward with meeting the RPS and meeting the objectives of increasing renewable, the biomass role in the renewable portfolio standard, is to make sure that we have the biomass on federal lands available to us.

Not in their entirety. That's not within -- that's not consistent with the federal laws nor with our state laws. But certainly it does need to be available for usage in both the RPS and the low carbon fuel standard. Those items that are going to provide us energy plus greenhouse gas benefits.

One of the major items that's, because of the inconsistency with which the federal lands have been treated in the past and how they're made available, is their opportunity to enter into long-term sales contracts. It's not wise for them to pursue a management structure that would enter into long-term contracts if they don't have the funding within their own system to fund the preparation of the sales for that material.

What can be done? That's very simple in that respect. It's take advantage of our opportunities, as our agencies and as a state, to encourage the federal congressional body to accommodate the use of at least some aspect of the federal biomass that's out there to contribute to the RPS and our other policy needs here in the state.

Things we are certain that -- earlier it was mentioned that there's a declining infrastructure. We agree. We have to have the equipment out there to be able to harvest the biomass and move it to the plants.

There's the matter of economic development zones. That's something we committed to work to with the Commission, and the Commission has been kind enough to fund the California Biomass Collaborative to move forward with testing the theory on whether that would apply to biomass through it's biomass management zone effort coming up this year. It will be completed by next year.

And the arrow doesn't work.

PRESIDING MEMBER BYRON: Mr. Wickizer, before you leave that slide, could you go back to the barriers, long-term sales contracts?

MR. WICKIZER: Yes, sir.

PRESIDING MEMBER BYRON: I'm not sure that I understood what you said. And I guess I'd just like, for clarification, did I understand you to say that funding is not available to make these contracts -- to put these contracts in place?

MR. WICKIZER: That's one of the situations that occurs, is that the -- the forest staffs are funded at a certain level to -- and I'm not speaking on their behalf, just from information I've learned in this case. They'll have to speak on their own behalf in that, Commissioner Byron.

But they receive a budget and it funds their level of work. And if that level --

PRESIDING MEMBER BYRON: But yet if they

have the contracts in place it would be a source of revenue, would it not?

MR. WICKIZER: It may or may not. A lot of that money does not necessarily go back to investment in the land. And that's getting into budget issues I don't think is my expertise in this case.

But it doesn't necessarily do that.

PRESIDING MEMBER BYRON: But you'll grant me that the revenue from the sale of the material would be greater than the cost of initiating and conducting the contracts?

MR. WICKIZER: Not in all cases, no. Some of the federal sales are zero cost sales. Or they pay -- it, in essence, goes against the cost of treating the land.

PRESIDING MEMBER BYRON: Okay.

MR. WICKIZER: On private sales I think your statement's true.

PRESIDING MEMBER BYRON: Otherwise private enterprise wouldn't conduct the sale.

MR. WICKIZER: That's exactly right. But government functions somewhat differently.

Move on to the permitting piece. There's been throughout the bioenergy interagency work group, and a lot of the questions going around biomass, permitting has always been raised as an issue.

For forest biomass the primary permit in this state for private land is the timber harvesting plant. Our department acts somewhat as a lead agency in that role, and it deals with, in general, the subsequent permits that would be required to do the removal of -- the harvesting of the biomass.

Such things a stream alteration agreements with Fish and Game, waste discharge permits with the Regional Water Quality Control Board, the list I have there.

What is the cost of doing a THV, what's the permit cost for us? Well, using those numbers on that last slide I just said, well, we have roughly 130,000 acres and about 400 permits. And these are back-of-the-envelope numbers, I acknowledge that.

So your average -- and our average cost per plan, in looking through our records, is something about $40,000. The range varies widely around that from 20 to 60, and in some very sensitive harvesting plans on the coast it'll exceed 100,000.

Well, then, how much biomass, if you were going to go in and do a fuels treatment operation and not including the logs, but just the biomass to end up with a healthy forest concept at the end of that, you're going to remove something between five and 13 tons per acre. That's from our vegetation management program, and some averages there.

And what's that average? Let's just say $7 a ton. So if you took that and you said that your cost of permitting per ton comes out to something around 14 bucks a ton just on a fuels removal issue. Not counting the commercial solids.

That's in the order, if I remember the numbers, right around a penny a kilowatt hour. That has a significant effect.

On top of that you have compliance with the regulations that lay on top of the review. And those run by the Board of Forestry something in the range of $10 to $15 per hour. That cost does not include additional cost to the landowner, their own expenses for having hiring foresters or other professionals to interface with the agencies.

Public concern can also add to the cost in a regulatory program, both before and after, as you know. It'll extend the time of review, add to the cost of obtaining a permit. And after a permit is approved, if it's of sufficient interest, it can result in litigation, which those individual cases cost a lot of money.

Permitting, what can be done? Things that we've talked about with the Commission over the years, and this is nothing new. Public education. We need to spend a lot more time demonstrating to the public what the benefits are of doing forest thinning or biomass harvest within a forest setting under responsible conditions. Meaning that you are paying attention to all of the co-benefits of that. And we need to be able to present the net environmental benefits of that activity.

We need to create lower costs for permits, and that would also, at the same time, reduce the impacts of the operations.

Quickly, the Board of Forestry, again in response to the BEIWG, Bioenergy Energy Interagency Workgroup, the Board of Forestry did take an action over the last year, and it expanded the idea of exemptions for harvesting of biomass alone.

But it chose the path of something akin to building code. Something where the activities that you conduct are very strict, and they're set out, and they're very limiting on the type of operations you conduct.

The Board's moving forward now in conjunction with our department to work on something that would be akin to what, under CEQA standards, would be considered a mitigation neg dec. You provide a lot of the mitigations out front. Again, part of it with restrictions on harvesting within the regulation, itself. And some design into the operation.

The cost of -- the benefit to that type of activity is that you'll have a lower cost for your permit, but your restrictions for your harvesting opportunities are somewhat limited.

The last thing on that is to continue to work and maximize the regulatory efficiency. And that's an ongoing event in all of our organizations. And that's learning how to work together better. And what time we spend, having it address more than one issue.

Biomass harvesting and transportation costs. We'll speed this up a little, I hope. On the harvesting, just as an idea that first table just gives you something out of a publication that's cited. That is in 2003 average harvesting cost to get the material to the landing.

The review that we requested from the California Biomass Collaborative was performed by Dr. Bruce Hartsough of University of California at Davis. We asked that they look at three things. An array of the equipment, the estimated cost per unit, and what can be done to improve the efficiency or reduce the cost of that harvesting.

We obviously contracted it out. This diagram appeared to be too difficult for our heads, and we didn't think we could really get around this. So we asked the University to address it for us.

The equipment past and present, the types of equipment or the pieces of equipment that are used in a biomass operation as that funny little word at the beginning, which means making small pieces out of big pieces. Densification, extraction, filling, loading, processing and transport.

On the productivity and costs the approach used by Dr. Hartsough, was using empirical studies; simulate those where necessary; cover the range of material from 4 to 10 inches, which is generally what you would approach on forest thinning, or fuel as the reduction type projects. And to apply those to a range of slopes, 10, 30 and 60 percent.

Used hourly costs at standard machine rates, and he used basecase scenarios to get to some of the answers you'll see in a moment.

Bottomline. These are the costs that he was able to determine after looking at a wide array of equipment and running numerous case scenarios.

The removal resulted in costs from $30 to $50 green dollars a ton, but those included roughly $12 a green ton in transportation.

Here's just a quick example of a scenario and what those do. I just included the picture of the forwarder because that scenario happens to include that. It's cut to length on the boles and you forward the material.

The graphs show you, give you an idea of where somewhere your optimal operating range would be, though your planning and management structure could be used to try to get you to that point.

Well, what can be done to get to some of it to reduce the cost? Some of the suggestions that Dr. Hartsough came out is harvesting on gentler slopes is more efficient with mechanized total trees. You can read the others. I think an interesting one is partially dry the material before you gather it, and chunk it up or chip it.

And then to continue on the transportation side, which is that $12 a ton, is to work on the efficiency on that. There's a couple of pieces of equipment that, one we're working with a demonstration in southern California, which are bins that you place on the ground ahead of time and load those. And then pull them up on a truck, similar to some of the garbage -- excuse me, waste management trucks you see around. Sorry, Fernando.

(Laughter.)

MR. WICKIZER: Then the other one is forest roads aren't like highways. They got kind of of like tight corner, if you've been out there. So, they developed a logging truck that's somewhat of an articulated carriage that hauls the logs out on those roads.

One of the problems is getting chip vans close enough to the landings to where you can load them efficiently and maximize the travel time, maximize the speed of travel, reducing travel time.

They've taken the bin and put it on a logging truck, in simplest terms. And there's some potential on that that we're seeing come out of San Dimas experiment station down in southern California.

Here is just another quick list of some of the items that we felt that could be improved. There's room for research in these areas on this type of equipment. Automated felling and bunching, continuous travel feller/buncher. Increasing strip widths as a management strategy. You could use it, but in the proper types of stands where there's -- generally the stand is younger and high density.

Develop a yarder/chipper, or yarder/loader feeding a separate chipper. It's a lot of the things that have been tried in Europe.

And then I think something at the end of that is that we can't leave off is the idea that there's always room to improve the training that you give to the operators and to the side -- to better lay out and manage those operations.

Dr. Hartsough gave us, kind of at the end of his report you'll see the statement. It's a typical one, nothing new. There's room to make gains, but it's going to take effort. There's no magic one answer.

But he does feel that there's room, through equipment selection, planning, training and operation to reduce the costs of harvesting somewhere from 10 to 20 percent.

We believe there's also room for research, development and demonstration that needs to continue on to get better improvements in some of this equipment.

And just a little whoopee at the end, just some of the ideas. Those two trucks are examples of -- the stinger truck in the middle is the type of van that's being developed. And you can see then the type of the bins and the type of roll-on/roll-off type system you see in the lower right.

So, thank you very much.

PRESIDING MEMBER BYRON: Thank you. I'm not sure about ending with a slide that shows, you know, six devices that all burn fossil fuel --

(Laughter.)

MR. WICKIZER: We figure that in when we're doing -- in the forest protocols, when we're doing greenhouse gas accounting. We certainly include a deduction for the fossil fuel usage for timber harvesting. So it is considered in our analysis.

PRESIDING MEMBER BYRON: Of course. Thank you very much.

MR. ORTA: Our next speaker is not present here at the workshop, but he will be giving his presentation through WebEx. Unfortunately, he was -- his presentation is a very large file, and he wasn't able to send it.

Our speaker is Mark Nechodom from the United States Forest Service. And we will attempt to access the wonders of technology to get his presentation on the screen.

(Pause.)

MR. BARKER: Mark, we got your presentation up. Go ahead and talk to make sure we have sound.

(No audible response.)

DR. NECHODOM: Now I think I just came on here. Are we on?

MR. ORTA: We can hear you, Mark.

DR. NECHODOM: Wonderful, all right. And you can see the presentation.

So thanks for the opportunity to present some of the research that we've been doing in support of really some discussion you've been already having today. Apologize that I wasn't able to join either personally or for the whole day.

I will note that it is actually really useful to follow Doug Wickizer and Greg Morris and Fernando, because I promise you they make up for a lot of deficiencies in my own presentation. So, pretty rick discussion.

Before I begin my more formal remarks, though, I thought I might fill in just a little bit. Doug, you kind of got cornered a little bit on the long-term contracts question. And I think I can help understand that a little bit.

The U.S. Forest Service has, under the Healthy Forest Restoration Act, been given expanded, what we call stewardship contracting authority. Which the central fulcrum point in it statutorily is enabling us to trade what we call goods for services.

What that essentially means is we figure out what the market value of something is on the land, whether it's saw blog or biomass, by ton, or another product, and we essentially bid or ask for bids for people to come and provide this service. Because the service contract is there for other purposes, you'll find in the purpose and need in the NEPA document something about fuels treatments or wildfire hazard reduction or some purpose for treating the land.

Of course, it costs money to do that. And whatever we can commercially -- off the land goes into the calculation, so that we essentially net out to zero, at least in the planning stages, to do that.

What actually happens very often in response to the question, and I apologize, I don't know who the questioner was, but the question was why don't we make money on these things. And the fact is that the cost of doing the operation to the specifications that we set, which are usually environmentally very stringent, very often exceeds the value of the material that can be taken off the site.

So what we often end up doing, and this not necessarily part of what the public knows -- we're not hiding anything, it's just that, you know, the public doesn't necessarily know that we often do this in a stewardship contract is because we need to get the work done.

We will use what we call forest account budget, which comes out essentially, you know, if we're doing planning out of our left back pocket, we pull money out of our right back pocket to be able to pay for things like short road access in putting the road to bed after operations. We may pay for brush disposal. You may see those big jackpot piles out there that we burn during the spring and the fall.

All those things cost money. And we pay for them out of those budgets. So that's part of the problem we're trying to overcome here, is there's simply not enough money in the system, as it's designed right now, to keep up with the market and et cetera.

So I'm happy to have a discussion about that, but I thought it would be worth a couple of minutes just to explain from the Forest Service side of things how that actually works, the stewardship contract.

Seeing no hands raised, I'll just proceed here. I understand, especially confirmed by being able to tune in from Greg Morris this afternoon, that a lot of what's going on here is we're trying to figure out where the values are that we're not really accounting for or accommodating.

The overall concern which we, I think, all dealt with for a very long time is the value of the biomass doesn't necessarily make its own way out of the woods. And we're also very concerned that if biomass becomes a very popular feedstock, and forest-based biomass from thinning particularly becomes a very popular feedstock for meeting our renewable portfolio standard or renewable target, what are the other effects that we may engage, i.e., are we doing environmental harm in some way that we're not accounting for.

That calculation essentially drove the very very brief version of the research that I will present here in about a minute. This research was funded by the Energy Commission through the PIER program. It was called the wildland biomass lifecycle investment project.

And we just wrapped it up last fall. And I'll give you really the very high points just to kind of explain how we approached it, but with an eye toward -- report on the research we did, the eye is toward somehow getting at this problem of how do we accommodate the values that aren't necessarily yet priced or monetized or traded in some way that effectively realized not only the value to society, but actually run market. So that we could get the work done.

The first slide here, I've basically -- what we have is essentially on the science and monitoring side, and I'm including in this some of the carbon accounting that Greg Morris is talking about. The lifecycle assessment work that we've done.

We have a lot of data, we have a lot of fuels, we're improving our ability to model, the datasets are getting better. But we very often conflate the policy and accounting side of things. Which would be something most notably like the California Climate Action Registry and now the Climate Action Reserve Protocols that the Air

Resources Board has endorsed and accepted with the proviso that a revision is provided.

We have now spent the last year and a half, several people, I'm sure, in the room were part of the process, in rewriting those protocols in order to provide the rules sets and the accounting sets that would enable carbon sequestration to move to market.

As everybody, I think, knows we're currently dealing with a voluntary market. The grand portion of purchases in that voluntary market are what we call precompliance credit. Because, to date, there is no compliance market for carbon ton.

But we can -- sometimes I think we see it on the foggy horizon. And with the Waxman Bill now in play, we may have a cap-and-trade and we may have a compliance market fairly soon.

So I wanted to put up this little diagram just to kind of show that there's a real balance in the system. And as I understand the driving questions of today's discussion, some of those questions are about how do you do the measurement and monitoring. But at the same time, what would the policy and measurement and accounting be like.

Just to give you a brief example, do you allow harvested wood product to be counted as a portion of carbon sequestration. Or do we allow the carbon that's stored in landfills, particularly California's high quality landfills, that are sealed and that have methane capture or methane reduction, requirements, et cetera. Are those creditable in some way.

From the science point of view there's a heck of a lot of carbon sitting underground from a policy and accounting point of view. There are other consequences. And, of course, there are cross-sectoral consequences that need to be addressed.

So, to divert a little bit, because basically what I believe I was asked to do is to kind of present some of the research approaches to how you might get at some of those questions.

Over the last four or five years we built the biomass-to-energy project. These are the three main purposes of it. Modeling lifecycle, environmental and economic values, and of course we're focused on forest biomass for energy production. We're not dealing with, as you saw in Greg Morris' presentation, the other three forms of feedstock, which are mill waste, ag waste and recovered municipal solid waste or recovered urban waste.

And to test the effects of different forest management scenarios on wildfire behavior, which we began in 2004 to focus on wildfire changes, because as many of you know, that on the national level we are focused on the national fire plan. And we were asking ourselves what are the effects of actually doing thinning operations at various times on changing wildfire behavior.

As the world moved fairly quickly into an AB-32 framing of the world, everybody became concerned, of course, about energy and carbon. And our project was somewhat amenable to getting answers to those questions.

And, of course, finally the purpose of the model overall is to enable a policy discussion that would allow some gaming of different scenarios. For our purposes, what we're trying to do is build the structure of it, so we tested it, comparing between reference case, I'll talk about this in a minute, and a test scenario.

But here's the basic stick figure

version of what we're trying to do. And I'm going to assume that when I move my mouse here in Washington, D.C., somewhere in Sacramento you see a pointer.

The landscape behavior with and without remediation is what we're interested in. And I'll show you a little more detail on this. But the landscape fire behavior is about -- there goes my mouse -- landscape fire behavior, testing the difference between whether you treat it and whether you don't treat it.

And if you do treat it, what we call forest remediation -- we're deliberately avoiding the word restoration -- forest remediation has cost and benefits associated with it. Some of the material would go to forest biomass for electricity generation.

We built the model so that the electricity component of it, that is the conversion technologies, could be popped out and you could plug in liquid fuel or other product, but it's the same thing. You essentially have collection, processing, transportation. Add conversion and you can do essentially lifecycle analysis on all of those steps.

So whether it's electricity that goes to the California grid, or it's liquid fuels that goes into the state transportation fuel distribution system, the model can serve all of those.

We have essentially a comparison then in the electricity side between forest biomass generated electricity, and we chose essentially to do both natural gas and the California grid, because we had endless discussions about where the marginal increment in the increased capacity or increased infrastructure and energy production in California would be. Clearly current trends say natural gas. We decided for our model purposes we would do both.

But we're interested, of course, in the big -- down at the bottom, which is net costs and benefits associated with doing remediation of various kinds. And running scenarios on those remediation -- or running scenarios on remediation.

The way we decided early to approach this was to use an actual landscape. I'll show you that in just a moment. So we used a real footprint of 2.7 million acres in the northern

Sierra. Real land uses, and actual data from biomass power plants. I suspect there are people in the room there who were some of the contributors to our data.

Our alpha test was done Westwood and Mt. Lassen Power using -- very generously provided us with a lot of the data for operations. Everything down to, you know, a bobcat moving chips to grease used for, you know, lubricants, whatever part of the process, et cetera.

And from there we built our beta test which we looked at operations from about nine different plants in the region.

And we basically just delivered the modeling framework using referenced case in the test scenario. The test scenario designed to essentially mimic actual practices so we got the mega modeling, or you could say several models hooked together. We tested against our own gut sense of what we'd expect.

The test landscape, as I mentioned, 2.7 million acres in the northern Sierra. You can see that this is a fairly significant area with a lot of variety in it. From Lake Almanor down to the dam is called -- PG&E calls it their staircase of power. As you know, there's several hydro dams on here. A lot of high-value assets.

Down the highway 89 corridor, down toward Lake Tahoe, there's a very high-value recreation and amenity landscapes, a lot of resorts, et cetera, a lot of recreation.

And, of course, a fair amount of timber production, commercial timber, about 14 percent of this entire landscape is in commercial production, which we modeled, as well.

We modeled it over 40 years in nine different domains. I'm just showing you this largely to demonstrate that there were a lot of pieces. And given my opening gambit here about where the big questions are, where are the values reflected in either the economic or the nonmarket values, I would say that the last four or five, the last four of them are really about the things that we would ideally like to quantify, if not monetize, so that we could essentially compare what we're actually getting to 6.5 or 7 cents a kilowatt hour from biomass land compared to maybe benefits that are better supplied.

Greg Morris' earlier work, about ten years ago, was showing that number very very conservatively to be about 11.4 cents a kilowatt hour. I suspect that if we were able to finish the quantification of these last categories we'd end up with much high values. But the trick would be to see what policies would be required in order to create markets for those values so that that could be reflected in the use of biomass power for meeting our renewable energy target.

I'll very quickly go over some of the approaches we used, fairly complex. I won't go into the weeds here. But just to let you know that this is a very data-intensive process.

On 2.7 million acres we had 82 different kinds of vegetation types, which we have in our forest inventory and analysis, what we call strata. We actually had 450 actual inventory plots within the region from which we drew data.

And we extrapolated those plots to 2200 different polygon vegetation types. And used that, what we call stratification, so that when we do our modeling and we burn, for example, or treat in a polygon, what we're testing is essentially the change in vegetation structure, given what we assume about the vegetation in that area.

Of course, the biggest disturbance

factor on the landscape is fire. And how we modeled fire was using 60 years of fire history data, we developed essentially a Monte Carlo map. Just what you see in front of you now.

The big red blots are areas where you have a very high likelihood of ignition that would turn into medium to highest fire. And in order to turn this into a modeling exercise, we had to create what we called, for each decade out of the four decades we modeled, represented an ignition point or RIPs. And we can get into the actual -- we will defer all of this because it's not really relevant. But there's a lot of weeds to get lost in, in the modeling of fire and reactions. Let's just say that we did it right, and we'll see what our predictions say.

The other factor when we change vegetation change factor, of course, the treatment. What you see before you are, in the colors and the patterns, representations of the actual treatments or veg manipulation that are on that landscape.

The pixilated stuff up around Lake Almanor, up around here, as I mentioned earlier, is commercial timber. They have, as many of you know, NTHPs or sustained yield plant, that are adjacent to the requirements, maximum size of clear cutting, if that's your technique.

We modeled both clear cutting and selective cutting. We had a lot of help from five major players in the industry to design these, including Bruce Hartsough, as mentioned, presentation earlier.

And the other parts are parts of public land that were amenable to some kind of treatment. We have treatments we model on those public lands. And those lines that go throughout the region are essentially what are called defensible fuel profile zones, which are the treatment types that are used by the Quincy Library (inaudible).

So we do this over 40 years. That means with each decade we treat, we grow, we burn. And the reference case simply grows and burns.

Now, I'm really disappointed to hear that my USDA system, sitting in my office in Washington, will not allow you to see this really cool graphics between these two. So I'm not going to dwell on it a lot. But what you would see if USDA were technologically advanced is each one of these representative ignition points actually burns and spreads out with each decade.

So you see four cycles or four decades of burning patterns. And you see very large blobs by the end of the fourth decade across the landscape in different shades of red. My apologies to the color blind. And then, of course, with the management you see different sizes of blobs because those treatments actually had an effect on both the size and the intensity of the wildfires that we modeled.

This is an -- slide; I'm including it for later review if you want to go over it. But that's part of the modeling structure that you have to get at.

But here's the basic equation. Those on your left, the circles and squares, the pentagons, are the representative ignition points. And you have on the right the pattern of treatment. And the big question is what change do you create in wildfires, in emissions both from wildfire and from treatment, as Doug Wickizer just mentioned. To the habitat and the economics of moving material around and on the landscape, in watersheds, et cetera.

All of those have submodels or

subdomains associated with them. And we then compile it all into one big set of results.

And here's essentially a sampling of some of the top, or some of the issues, some of the results that we found, just in testing the models, does not -- this does not include future scenarios that our recommendations to the Energy Commission, we presented our results a couple of months ago.

We recommend about four additional scenarios like a carbon maximum, a wildfire maximum, et cetera. Won't go into those right now.

But these are fairly impressive results, just for essentially modeling the difference between over 40 years of letting it grow and burn without any treatment versus doing the treatments as we currently see them across the landscape.

The 22 percent reduction in the extent that's the footprint of wildfire. But more significantly, we found a very very radical shift in what used to be very high severity fire, and it's the percentage of a given fire footprint that resulted in pretty toasty burns.

Shifting that down into what we call

mixed lethal, or nonlethal, which is pretty much what we're looking for, if you're doing an underburn. Fairly significant shift in those categories.

The greenhouse gas numbers are total system. And with saw log production removed from the lifecycle assessment calculation. So essentially the greenhouse gases associated with the thinning and burning, the changes are pretty significant.

When I first saw this result I embargoed the data instantly, and I said to my team, you've got to go dig around in those gigabytes and terabytes of data and make sure we've got this right. So we have triple and quadruple checks of this number. We're very confident that, in fact, our lifecycle assessment number shows 55 percent reduction in greenhouse gases throughout the system over 40 years.

We also find reasonable reductions in wildfire damage, although those are questionable numbers because of the techniques by which you establish the value of a wildfire damage are still, I think, even a lot of (inaudible).

Our firefighting costs, of course, are

fairly crude, but, you know, not an insignificant amount because of reduction in severity and footprint.

And we find, we can't go into the data right now, some pretty interesting impacts in watershed and habitat quality.

We found it fairly interesting that applying the treatments over 40 years habitat quality just didn't show much of a signal across all of the 120 species, or the 14 guilds of species that we tested.

But as I understand it, from actually a conference call this morning, the Energy Commission's pursuing an extension of that habitat analysis, largely because, as I said initially, we're very concerned that the pursuit of forest space feedstock for biomass energy may have impacts on habitat and other services that we don't fully understand.

The right-hand column I'm not going to go into significantly, except I will point out, just as my final moment here, that I think this comports with Bruce Hartsough's and other people's showing that our average costs in all of the different treatments, commercial, public land treatments, are about $68 a bone dry ton.

It's not out of the realm, comports with some of the stuff that Greg Morris presented earlier on, and Bruce Hartsough, of course, has done some of -- in fact, Bruce Hartsough was the source of a lot of this data. So I hope Bruce Hartsough is being consistent.

And what that translates into in the final bullet is this is a very odd number -- again, we had to really double-check this -- is $8.20 a bone dry ton is what would be available for fuel purchase if you were to follow a kind of standard pro forma for building a biomass plant, from the ground up, in 2006. $8.20 a bone dry ton.

Now, why, you may ask, are we still out there paying between $20 and $60 a bone dry ton. I think there's several reasons; actually I'm sure that (inaudible) there in Sacramento is full of at least a couple of those people have really good answers to this.

I do believe our answer to this is because many of the plants are still either under SO4 contracts or the equivalent. They've amortized their debt. There are other things going on.

Of course, the feedstock mix makes up for the fact that the higher priced forest waste may be offset. I'd be interested actually to hear from those, there are probably alternative ways of suggesting this. Or we could be completely wrong about this number. I hope not.

But let me finish on -- I'm actually going to skip this slide in the interest of time. But refocus on where we started.

We're involved right now in discussion in Washington, the main vehicle on climate legislation is Waxman/Markey, as many of you know. Currently the draft, 70 percent of the emission reductions or offsets will come from land-based offset. That means largely forestry and agriculture.

And that's a pretty high charge. But we know that it's not free. I think that's a lot of the discussion here. We're now beginning to have to, if not price, at least de facto price, or act as if there were fungible or comparable values associated with the things we're interested in on the landscape.

And the real reductions have to be real

reductions. This is where C-CARB, Board of Forestry, and ARB, along with the Energy Commission, we have to make absolutely sure that any reductions that are claimed under a cap-and-trade program are real. They're not indulgences, they're not forgivenesses.

And that means we absolutely must know what we're buying. And that, I think, is sort of the summary thought for me, is are we properly quantifying and ultimately, if possible, monetizing the suite of things that we care about so that we can understand whether we're actually getting something for what we're paying.

So that's basically the end of my remarks. Again, wish I could be there with you. I'm happy to take any questions, if that's possible.

MR. ORTA: Mark, this is Jason Orta. I have a followup question. And this is with regards to your estimate of greenhouse gas reductions.

Is part of that estimate consist of an increased survival of larger trees?

DR. NECHODOM: Yes, it does, actually, What we -- let me make a distinction here, because one of the scenarios that we have recommended we would run, and in fact in another entirely different project in the Forest Service we did something of the equivalent in doing a scenario that we remove a lot of small stems and grow a lot of bigger stems that were more fire-resistant.

We're not doing that in this particular model result. But we are assuming higher uptake rate, sequestration rate, which is actually reflected in what are called our tree list data.

So we're not generalizing, that is, tree growth in some generalized way. We actually, in each of those polygons that's treated or burned, we actually model, using forest vegetation simulator, the actual growth post-disturbance.

And find in some vegetation types a very rapid accumulation of biomass or carbon -- resistance. So that does go into the calculation of how much is being (inaudible).

MR. ORTA: Thank you.

PRESIDING MEMBER BYRON: Dr. Nechodom, this is Commissioner Jeff Byron. Thank you very much for this summary. It's -- I just turned to my Advisor to ask if we had seen this report. You know, we often approve the research projects, we don't always see the results.

So, it's --

DR. NECHODOM: We promise to show you.

PRESIDING MEMBER BYRON: No, it's very good. And I assume that this report is available with the conclusions and the findings. Correct?

DR. NECHODOM: Yes. Actually Linda Spiegel is the PIER program contract manager who is now, I believe, the final product is currently undergoing final publication and review in the PIER shop.

But I see no reason whatsoever, you being one of the Commissioners, that you shouldn't be able to see the entire tract.

PRESIDING MEMBER BYRON: Sure. Yeah, I'm not concerned about that. It's just there's so much information that goes through here. These are very interesting findings about the terawatt hours and fossil fuel generation that's been saved. There's a lot of interesting data here.

I'm also interested, as you said you went back and verified a lot of this information. Has your work been peer-reviewed? P-e-e-r reviewed?

DR. NECHODOM: Both P-I-E-R and p-e-e-r,

yes. Especially the lifecycle assessment model was of greatest concern to us, so it had actually independent peer review.

We also worked along through the project with the technical advisory committee on which serve actually some of the people in your audience. And instead of convening the entire technical advisory committee every time we had some new product, we actually farmed out to portions of the advice from them, and then certain portions, like the habitat modeling, had blind peer review. We had review from the national labs on the lifecycle assessment.

So, yes, we had very thorough review. I actually wouldn't mind having even tougher review on some of this. But, you know, time and resources wouldn't allow it.

PRESIDING MEMBER BYRON: I'm sure we can accommodate that. A question, I'm not a biologist, but the 22 percent reduction in the extent of wildfire reductions, how does that equate -- I'm trying to get a comparison in my mind of the NOx emissions from that versus if we were to, I don't know how to put it, collect and burn this to generate electricity, for instance?

DR. NECHODOM: A great question. This is basically modeling that is in its infancy. Our emissions modeling from burning has grown from, in the early '80s with the Pacific Northwest Labs testing essentially actual fires up close with specialized equipment, and getting pretty accurate readings.

But a lot of the modeling came from prescribed burns, because of the safety issues of actually getting it with sensors.

Some of the improved data collection from actual wildfire is allowing us to correct for that. We do show the difference between a wildfire burning in high intensity, much higher NOx and PM2.5 and -10 emissions than we show by dragging it out of the woods with all the emissions associated; putting it into a biomass plant; and generating electrons with it.

Now, you're still producing just as much carbon dioxide and carbon monoxide. The carbon's basically the same amount. But you're pointing to something very important, as a caveat in some of this modeling, is you're changing other things like nitrous oxide, NO2, NOx, NH4, other constituents by essentially burning it under controlled conditions.

PRESIDING MEMBER BYRON: So can we get a handle on those numbers for comparison sake? I mean, I think if I'm understanding this, that that's part of the argument that can be used for why it's good to collect and burn this for electricity, regardless of the NOx emissions from it.

DR. NECHODOM: That is the argument, yes. I mean the argument is not only the emissions side, but the increased damage to other assets of concern, or values of concern. Whether it's recreation, habitat, et cetera.

And we were fools enough to try to build models around all of those values. Some we were quite successful, and others need a lot more.

PRESIDING MEMBER BYRON: So more work is necessary?

DR. NECHODOM: Absolutely. And I'm not saying that as a statistical researcher who has his hand out saying could you write us another check. We're actually having a lot of this discussion in Washington. Our R&D in the Forest Service is focusing a lot on resolving some of the emissions problems.

And some of the discussions we're having, the Waxman Bill and others, is some of the auctions allowing proceeds may go into R&D to help us to get a better handle on these numbers.

So I think in the larger public policy issue, these numbers -- knowing these numbers better will have a marginal value depending on the value of carbon or other impact.

So if we really really care about the carbon differences of burning wildfires versus burning in a biomass plant, we'll probably need to make that investment at a fairly significant level.

PRESIDING MEMBER BYRON: Good. Well, thank you very much for being with us. I assume you're in Washington.

DR. NECHODOM: I am.

PRESIDING MEMBER BYRON: Okay.

DR. NECHODOM: Yeah, somebody there owes me a beer, because it's 20 to 7:00, and I'm missing my --

PRESIDING MEMBER BYRON: Yeah, it's a little late. Thank you very much.

DR. NECHODOM: Just as a note, though, I am periodically in California. If you'd prefer at the Energy Commission that I comment, give you the full presentation on the research, I'd be happy to do so.

PRESIDING MEMBER BYRON: Okay, thank you for that offer. And thank you for reducing your carbon footprint by staying in Washington.

(Laughter.)

MR. ORTA: Well, that's all we have for this group of presentations. And like to open it up to stakeholder comment.

And I would like to call Phil Reese from the California Biomass Energy Alliance. And, Phil, I promise I won't cut you off this time. I apologize for --

MR. REESE: Don't you worry about it, Jason.

MR. ORTA: -- doing it this morning.

MR. REESE: Commissioner, I can give you a specific answer to the question you just asked Mark.

Back in the middle '80s the Air Resources Board sponsored considerable research at the University of California Riverside atmospheric lab, done by a Professor Edwin Darley, whose task was to quantify the emission rates of criteria pollutants, including NOx, from the open burning of a wide variety of materials, from agricultural waste to forest materials and the like.

The results of that study -- I'm sure you still have the report around, if you don't, I do -- showed that for NOx each -- the numbers did vary and they had to be corrected to Professor Darley's moisture content. He did not use bone dry.

But, in general, the offset credit, to harken back to my earlier discussion today, that was awarded for eliminating a ton of open burning of biomass was 4 pounds of NOx.

So, many of the early California plants, probably half of them, were permitted on the basis of eliminating open burning using Professor Darley's calculation of what would have been emitted for each criteria pollutant by each ton of open burning.

That agricultural protocol, which is what it was called, was legal until about 1990. And for reasons I don't think I ever knew, the elimination of open burning was eliminated as a source of offsets.

Now, to continue from that point to

where I was going this morning when I said that the lack of emission offsets has completely stopped development in southern California, and offsets are required with limited and extremely expensive availability in the northern half of the state, the ag protocol -- well, there is still some open burning allowed.

The open burning of ag residues is being phased out in the San Joaquin Valley, but the burning of orchard prunings, of which there are hundreds of thousands of tons, is not yet outlawed, and has another year or so I think before the ban becomes effective.

If by some mechanism the outlawing of that open burning could be exchanged for a requirement that those prunings are taken to a biomass plant with the associated offsets granted, would be one mechanism to grow the biomass industry.

A second, sort of a subset of that, would be to allow offsets for the collection of the, the word's been used here today, the undergrowth, the brush, the thinnings of forests, on the theory that it eventually will burn, either in a prescribed burn or accidentally in a wildfire.

The offset situation is the deal killer. If you can solve the money problem. Given unlimited money you still can't do it if you don't have the emission offsets.

Now, the only other avenue that we in the industry have thought of to expand the current solid fuel biomass industry is expansion of existing plants -- and I believe I mentioned this this morning -- through the installation of modern, albeit very expensive emission control equipment on existing plants, reducing their emissions, thereby creating offsets allowing expansion of those existing plants. I absolutely know that can be done, because I've done it.

The other problem that has happened, there was quite a discussion this morning, and I forget which speaker said it, that something to the effect of a third of the contracts have been cancelled.

Being in a position where my name and phone number are on the biomass website, I get lots and lots of calls. And I will tell you, from an industry perspective, those contracts that have been cancelled is because it has become completely clear, without question, that the project that's the subject of the contract, is not going to be developed.

There are a number of others, I guess I could tell you specifically, which are not going to come to fruition for the single reason that the contracts have been signed at energy prices that are too low to bring a project to completion.

I know this because I get phone calls from the holders of those contracts who are trying to market it. Because they have realized the plant can't be built.

So, we've got these two problems. We've got the money problem, which is hampered by the market price referent, which has become a de facto upper limit on what the utilities will pay for renewable energy.

It's not high enough to support the development and construction of a greenfield biomass plant. It may be high enough to support the restart of an existing, but there are only a very few idle plants capable of being restarted that are left.

Now, I did want to speak very briefly to the question, I think it was number 17, that was posed in the agenda for this. It spoke of doing treatments to fuels to make them somehow better so that the plant could become economically more efficient.

One of the categories mentioned was torrefaction or pelletization. I've done some research on that. The industry has long felt that we get the fuel the cheapest way we can, and keep our suppliers in business.

But I came across a -- I located a report on torrefaction for biomass upgrading that was presented at the 14th European Biomass Conference and Exhibition. It was done in the Netherlands, and the two facts that came out of it were the torrefaction process will increase the mean value of the biomass by roughly 15 percent. Oh, that's good.

But the cost of doing it is 40 to 50 Euros per ton. Now, if you remember Greg's prices, that could double or triple the price of the fuel for a 15 percent increase in energy.

Thank you very much.

PRESIDING MEMBER BYRON: Thank you.

MR. ORTA: Next is Julie Malinowski-Ball, who is also from the California Biomass

Energy Alliance.

MS. MALINOWSKI-BALL: Thank you, I'll make this brief. Julie Malinowski-Ball, representing the California Biomass Energy Alliance. Yeah, we're taking a couple bites at the apple here, but what the heck.

PRESIDING MEMBER BYRON: You've been here all day. You don't have to be brief. Go right ahead. Thank you for coming.

MS. MALINOWSKI-BALL: I don't want to repeat, you know, the information provided to you this afternoon. I think that the presentations that you heard today, this afternoon, were great. The things that Greg Morris said, and I want to back up what Phil Reese had said, also.

I just want you to think about the biomass industry and removing barriers and just two pillars. You want to get greater access to the fuel, we know it's out there. We've known it for the last 15 years. The fuel's out there, how do you get to it.

Well, you get to it by opening up access to it, by talking to the Integrated Waste Management Board, dealing with the ADC issue, which is what you're exactly doing. And talking to the CalFire and U.S. Forest Service, getting at the fuel that's out there in the forest. That's exactly what you're doing.

But there's just so much they can do, when you don't talk about the other pillar of barriers. And that is cost, which Phil has already talked about. You talked about the MPR.

All the right agencies are here today. And they're participating in the bioenergy interagency working group. But who's not here today, who should be, is the Public Utilities Commission, who is addressing several of the cost barriers within proceedings on the RPS.

I would love you to ask them where they are in their proceeding on dealing with this 20 percent biomass by 2010 or 2020 issue. Where --

MR. SPEAKER: -- finish my presentation.

PRESIDING MEMBER BYRON: Those on the phone, please put it on mute.

MS. MALINOWSKI-BALL: I would ask them, you know, where they are in that proceeding. Comments were filed, I think three years ago, without a decision. They brought up issues about putting adders on contracts for recognizing the benefits of biomass, to, you know, other feed-in tariff type options.

I would ask where is the Air Resources Board today. Where's their presentation how they're addressing biomass issues, in particular, right now, in their low carbon fuel standard proceeding.

Because right now, today, you have an agency such as the California Energy Commission that's doing what it can to promote the biomass industry, but over here at the Air Resources Board, another California state agency, who is actually considering putting restrictions on the type of fuel that we use, and saying that's not renewable.

So, the importance of the interagency working group is taking not just a few of the agencies, and doing what it can, but taking all the agencies involved. So I would encourage you to continue working together and addressing those issues.

And, in fact, Commissioner Boyd has done a yeoman's job representing those interests, both at the bioenergy interagency working group and the forestry interagency working group, which is now looking at that low carbon fuel standard definition.

So I want to thank you for today. I thought it was very useful, and we will continue to work with you. Thank you.

PRESIDING MEMBER BYRON: Good comments, Ms. Ball. Thank you for focusing onto those two key issues. There are others, of course, that I've noted along the way here, too.

And it's interesting that you bring up Commissioner Boyd. As you know, he's been involved in one way or another in this activity for, well, we don't want to say for how long, let's just say for a great deal of time. He's very dedicated to it.

I'm somewhat of a newbie and learning fast. But we will take this up in a substantial way in the IEPR. He and I both are on that committee, and feel that there are some strong recommendations we can make.

You make a very good point. We are missing a couple of key agencies here. And, in fact, we discussed that briefly here at the dais earlier. We, I think, need to take a little bit of a leadership role, lacking that role that's elsewhere.

But thank you for your comments.

MR. ORTA: The next commenter I have is on WebEx. The person's name is Will Grady.

MR. GRADY: Hello. Can you hear me?

MR. ORTA: Yes.

MR. GRADY: Yeah, I'm someone who had to leave my home in 2003, and again in 2008 because of all the fires, you know, that you guys all talked about, you talk about taking care of. You talked about all this other interesting stuff. And I end up breathing the smoke.

So where I live in southern California, you know, bark beetles have killed lots of trees. There was a removal program going forward. It seems to have stopped basically, once Southern California Edison cleared their right-of-ways, that was the end of the clearing.

I know that our representative, Jerry Lewis, got money appropriated through the Healthy Forest Act that just sits there in a pile because the Forest Service is unable or unwilling to write forest stewardship award for a long-term clearing of the forest, which would, of course, create the fuel for all these people that would like to develop biomass plants.

So I guess my question is I know there is a tremendous short-term need to get these dead trees out of the forest. And I also appreciate that in this short term it would be extremely difficult to justify the construction and operation of facilities.

But, you know, can't we reach some middle ground here to get these trees out of the forest and get them taken care of. And, of course, it would be a lot better to turn it into electricity than smoke that myself and my neighbors breathe.

Now, there's a question that could be answered by anyone in the room. I'd like to know what you guys think.

PRESIDING MEMBER BYRON: Mr. Orta, go right ahead and answer that question.

MR. ORTA: Well, thanks for listening to our workshop. And that's the whole purpose of this exercise is for, is to gather information from fellow state agencies and federal agencies and from the industries to do that.

As you can see from these presentations, the obstacles to getting these out are various permitting issues and the costs; and these biomass facilities that would use this fuel face other obstacles, as well, as Mr. Reese and Ms. Malinowski-Ball have pointed out.

So we are -- if you've been following the workshop from this morning, the Governor has set some very ambitious bioenergy goals which would essentially require us to get as much feedstock material from as many sources as possible.

So, we need -- we probably need some of that material from the forest. We can't promise that it will happen tomorrow or next week. But we're working hard on it.

PRESIDING MEMBER BYRON: Mr. Grady, this is Commissioner Byron. I didn't mean to make light of your concerns. Obviously they're very serious. And that is one of the aspects of what we're trying to address here today.

But I think it's fair to say that we've got a number of different laws that have been passed over the year, a number of different agencies that have different responsibilities as a result of those statutes. And we're in conflict.

And we're trying to sort that out to a great extent, and we need to figure that out, both at the Legislature, as well as how the agencies can navigate the path that we're on.

You stated in a very simple way, how do we get this material picked up and out of here so that when it burns I don't have to breathe it. And that's one aspect of what we're trying to work on.

I'll give you the last word. Is there anything else you wanted to add before we go on to another commenter?

MR. GRADY: Yeah. I have a very simple, you know, for all the rocket scientists that don't understand, you know, I could unscrew the filters from my respirator and send them in the mail to you, if you don't understand the difference between a heck of a lot of smoke and the occasional, measured in parts per million, NOx, you know.

You're talking about a facility that will have likely a state of the art particulate emissions removal. To in any way relate such to open burning is happily (inaudible), illogical.

Once again, for those of us that do breathe the smoke, yeah, we endure the NOx. But I think the smoke is a lot worse for myself and my family's health. And I would like you to clearly use what I might say, common sense.

And I thank you for listening to my comments.

PRESIDING MEMBER BYRON: Thank you, Mr. Grady.

MR. ORTA: If you would like to stay online, Mark Nechodom from the U.S. Forest Service would like to respond to some of his comments.

Mark?

DR. NECHODOM: Thanks. I just wanted to reinforce what's been said about some of the, I wouldn't call them barriers, because what we have been calling barriers are really competing social concerns about how we manage our forests.

And speaking on behalf of (inaudible) 53 percent of the forested area in California, I don't mean to be so magnanimous, but I do want to say that the Forest Service has an ongoing and grave concern about the condition of those forests, and the degree to which we are able to manage them.

Part of the constraint of managing those forests is what we've all been referring to as the social -- it's not a complaint, it's really an observation that as yet we have not met a broad social consensus that the cost to the gentleman who just spoke, in public health. Go to any large pulmonary department in any large university hospital in the state of California, and they'll tell you exactly what the gentleman was talking about.

There are large public health concerns. There are forest -- long-term stewardship concerns. And we have found ourselves basically unable to meet competing demand on the public lands because we have not met the agreement about what's a sustainable, long-term sustainable, healthy, resilient forest that burns occasionally because that's just nature. But doesn't burn catastrophically. And still provides us with a whole stream of ecosystem services like water filtration and timing and key habitat, et cetera, some of the list that you've already seen.

We are working here in Washington on figuring out what are the terms of sustainability that would have to be met in order to change the provision in the Energy Independence and Security Act that essentially forbad the use of federal biomass in meeting renewable portfolio standard with renewable energy target.

We consider that a concern expressed by some of the people who are not sure that if we turn that into a creditable or qualifying feedstock for renewable energy, that we're not going to do a big scale of bad things out in the forest.

And we need to meet that social concern, but at the same time, our earlier studies to which I referred very briefly in my presentation, shows that we, under business-as-usual, on 20 million acres of national forestland in California, are accumulating, starting in 2006, 2007, from about 825 million metric tons of above-ground, standing, live biomass. Under business-as-usual, current burning and treatment will by 2050 reach above 1.2 billion metric tons of standing, above-ground, live biomass.

We also show in our modeling that somewhere around mid-century that huge carbon sink is going to start wobbling like a top and destabilize and start burning up very erratically. And we have not even calculated in the regional climate models that suggest, all of them, that it will be hotter and drier toward the end of the century.

We, quite frankly, don't know what to do about this problem. Because we are accumulating, we are doing in some ways the public a big favor by sucking a bunch of carbon out of the atmosphere, but we're going to put it right back there with results affecting all those other -- services that we can't yet protect.

We're not really happy about that scenario, but we don't know exactly what to do about it.

PRESIDING MEMBER BYRON: Well, on that cheery note, do you have more cards for this --

MR. ORTA: I have one more.

PRESIDING MEMBER BYRON: Thank you, Dr. Nechodom, we're going to go on to the next comment.

DR. NECHODOM: Okay. Sorry to interrupt, and actually if there are no comments specifically for me, I am going to go ahead and sign off. I appreciate the opportunity to present today, thank you.

PRESIDING MEMBER BYRON: You're welcome. Thank you. Enjoy the beer.

(Laughter.)

MR. ORTA: Jim Jungwirth.

MR. JUNGWIRTH: I'm from the Watershed Research and Training Center in Hayfork, California. And I have to report to you that the wobble he is talking about has already started in my county.

We burned about 250,000 acres, mostly 90 percent federal land, last year. We have burned more timber since 1980 than was burned in the Trinity Forest from 1900 to 1980. It's an astounding amount.

We have, in one fire, one of the six major fires we had in Trinity County last year, we had a million tons of standing dead material left. So if you looked at that 13,000 tons of material they talked about in L.A. County, we generated 73 days of material that would have been generated by what some 10 million people, in four days in my forest.

So, we've got some real problems. And we're kind of living right in the middle of it.

I was kind of surprised in all the presentations today that I did not hear more about thermal use. As a public lands community, we face the problem of not being able to generate enough biomass to facilitate the construction of a large biomass plant. So we're having to look at other alternatives, densification being one of them. Thermal energy use for municipal and community buildings being another.

But I would hope the Commission would take part of its energy and take a look at that part, because I believe -- our first ten-year storage of contract that he was talking about, is going to be awarded this year. And we're going to generate about 20,000 tons of material.

Well, if you looked at that in terms of biomass energy production, that's about 1.2 megawatts of power which is generally below the economic feasibility for production of a biomass plant. So we have to look at options.

The same thing with the extraction equipment. If you're dealing with that kind of tonnage how can you afford to pay $2 million for the equipment to take it out of the forest.

I think the public lands communities within California are stuck with an additional problem of not only having all of this biomass, but having it come out in small enough amounts that we have to look at scale as the biggest problem to overcome.

So, I appreciated everything that was said today, especially the federal presentation.

Just one more point in terms of our looking at the ten-year stewardship contract, and why we finally got one. Is that the change in the federal regulations involving multiple year contracts, up until this point, said that you had to do all the planning for all ten years in one year.

Well, the allocation for planning in any one year was not enough to be able to plan for ten years. So they finally got to the point where they were saying, we will allocate the money in the year that the plan is going to be implemented. So that was the biggest single change that allowed us to do goods-for-services contracts.

The challenge for us, and the goal for us, is the realization that the Forest Service has a pot of money for fuels reduction. The goods-for-services contract essentially puts the onus on us, as the contractors, to try to figure out a way of being able to increase the value of the material being removed in order to pay the Forest Service more, or to have them pay us less, so that we can treat more acres. And that's the way the system works.

So, obviously when you look at an average cost of $68 a bone dry ton, and a value of $8.5 per bone dry ton, we got a gap that we're going to have to work pretty darn hard.

But I believe again scale is going to be our biggest problem. We're going to need to figure out how to be able to produce more closely oriented systems to the forest in order to be able to reduce transportation costs, and in order to be able to diversify the generation of power to the point where we don't have to build new transmission lines. We need to stay within the distributed power system.

And so to the extent that you can help those of us up in the mountains, do that. We'd appreciate it.

PRESIDING MEMBER BYRON: Thanks for coming. Excellent comments, you've thought about this a great deal, appreciate it.

MR. JUNGWIRTH: Oh, yes. Thank you.

MR. ORTA: We could either take another break or we have one more presentation.

PRESIDING MEMBER BYRON: I think we're

going to plow right on through. Anyone, of course, is welcome to take a break as necessary. But I think we should continue on, Mr. Orta.

MR. ORTA: Okay. Our next presenter is, we have Kevin Sullivan from KEMA, to talk about cofiring biomass at coal-fired power plants.

MR. SULLIVAN: Thank you. At least being the last presentation we're going to get to the hard stuff now, and talk about the clean coal.

I actually have a presentation, overview and a little bit of an analysis, very top-end, envelope analysis of cofiring with the coal-fired power plants. And you'll see that this is partially in the WECC region. And we've had a look at the data within California, itself.

So the discussion will go through looking at the potential of the fuel switch capability within WECC and California. We're then going to look at the technology, what is cofiring.

We'll also have a quick look at the biomass supply chain. And I do have some nice dirty samples of torrefied wood. And then we'll get into a little bit of an estimate of the potential for cofiring within the WECC region.

And then we'll finish off with some

challenges and some of the issues the industry faces.

So, by way of introduction, the cofiring, this is a technology that's been around for some time. Certainly in the U.S., there's been a lot of studies, but not many large-scale projects have actually taken ground on the subject.

But we've seen your drivers, so we're very hopeful that we'll see more cofiring as a result of the renewable portfolio standards. The fuel-switch issue, as it comes to meet climate action plans and RPS targets, and some of the opportunities that may arise out of cheaper opportunity fuels.

And certainly with the stimulus package and things that are happening in the economy, I think the job creation potential is also of interest.

This slide basically gives you an overview, but before you focus on the data I want to make a point about what is WECC. Any slide that is shown here really excludes any part of Canada or Mexico. It also includes the entire states of Montana and New Mexico, but excludes the entire states of South Dakota and Texas, the partial states that were in the WECC regions.

And the purpose of that was to really get an idea of the adjacent states to California, and the potential within those states for coal-fired cofiring.

So you can see that are around about 133 plants in that region, with about a 35 gigawatt nameplate capacity. And largely it's anthracite coal, bituminous coal and sub bituminous coal that is being burned in those power plants.

PRESIDING MEMBER BYRON: Mr. Sullivan, maybe this is the breakdown here. In the slides that you've got for us are blacked out where the tables are.

I want to ask my question. You have a breakout for the coal-fired power plants that are in California?

MR. SULLIVAN: Correct, we have it.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. SULLIVAN: Small as it is, but it is here.

The next slide actually addresses some of that. We looked at the potential within the

California area. And we also looked at two forms of cofiring. Either a low-cost cofiring solution, which is a low capital expenditure way to burn biomass in a coal-fired power plant; or a high-cost solution which involves much more fuel handling. We even go up to 30 percent.

But if you look at the kind of numbers that come out of that study is California around about 4.4 gigawatts. And the potential in either the low-case scenario or the high-case scenario.

I think the important thing is to just give you an idea of the kinds of potential with cofiring. We did not look at the 100 percent option, as this would probably involve a lot more capital expenditure.

I'd also like to make a connection to the costs of generation because we looked at this option in costs of generation as one of the lowest costs, around about $500 per kilowatt installed or below. So, there's a few more detailed charts which might give you a better feel for the potential, as we go through.

This again takes the WECC region and identifies the 33 gigawatts of installed capacity shown on the table on the top. And in the bottom talks about the gigawatt hours in the WECC region, as we defined it, totaling 225,000 gigawatt hours.

So, in theory, technically the potential could be as much as converting 100 percent of these power plants into biomass-fired power plants. And providing 100 percent of replacing the coal and putting biomass to the tune of basically 33 gigawatts. I think that is the new definition of a technical potential.

In California alone, the breakdown that we came up with, of course, is a lot smaller. The nameplate capacity is only about half a gig. And if you look at either a 10 percent or even a 30 percent cofiring, on the high side you would get up to close to 1000 megawatt hours of biomass potential. So obviously an important factor here is the purchased energy from neighboring states.

So, I'd like to give you an overview of the technology. Very briefly look at what is cofiring, and why is it viable, and when it's become viable.

Certainly you need a biomass supply. That is a key part of it. You need an area to put the feedstock. And most coal-fired power plants do have significant area for coal at a stockyard, so that is normally not the big hindrance.

You need a preprocessing unit. Some of the biomass, unless it's been torrefied, needs a significant amount of preprocessing. And you need to make sure that you don't have to derate the unit, and also look at no degradation in combustion properties, which is one of the reasons why to take a coal-fired power plant to 100 percent biomass firing normally would involve a major redesign of the thermal processes and the heat rate, itself.

Based on our modeling most dominant economic parameters, of course, is the price of the coal. I mean, as coal price goes up, biomass firing becomes very interesting.

And the specific investment costs are very different depending on which plant you're looking at. Most coal-fired power plants are over 40 years old. And as a result they have a certain amount of over-design, but they're all unique.

And they've all been churned over many years to operate effectively and cleanly using burning that nice clean coal. And, of course, the CO2 price is another key factor.

So, we've seen most of the studies talk

about a 1.7 or up to 2, or even up to 3 U.S. dollars per million Btus. As a price, makes it very viable in today's climate without any RPS or carbon allowances to really combust biomass.

This little chart gives a sort of simple overview of how you take biomass, pretreat it and either inject it directly with the coal, route one; or through the mills, route two. Or directly into the burner, into the combustion chamber of the boiler, route three. And the fourth route is, of course, you could gasify it and produce a syngas. And that syngas could be burned by burners in the boiler, itself.

And the reason why I mention these four routes is depending on the design of the power plant and on the percentage of cofiring, you may want to consider multiple routes. Also if you are using raw or wood-based biomass, or torrefied wood, it would make a difference to where you inject it.

For example, if you're using torrefied biomass you could inject it in route one. It looks like coal; feels like coal; smells like coal.

PRESIDING MEMBER BYRON: So, you said

both preprocessing and pretreatment. What are those processes?

MR. SULLIVAN: Actually when I talk about preprocessing I mean both the pretreatment and the milling and any other aspects that you have to do with the burners.

But the pretreatment, itself, depends on the type of biomass. Most of it involves drying. If it's a woody based biomass it is more effective to dry that biomass before it is injected into the boiler.

It's not very high tech. You know, this is really just a burning process and making sure that you can deliver at the effective rates into the existing flow of fuel.

Actually, this is a chart that leads straight into that question. If you're dealing with dry powder, you have to store that in a silo. If you're dealing with a wet straw, you also need to put that in a pit form. Same with chips, wood chips.

Of course, if you're dealing with torrefied biomass, you just need to have a stockpile and treat it like you would coal. So there are different processes involved with the pretreatment as shown in this diagram.

This is kind of a detour, a little bit of tourism into coal-fired power plants. As we all know, over 50 percent of our energy in the United States comes from plants that look like these. And plants that consume coal.

There are only really four aspects or five aspects of waste that need to be considered in a power plant. You can optimize the fuel supply. You can optimize the combustion. You can mitigate the gas emissions. And lastly, you can deal with the sold waste. And the purpose of this chart was just to describe those four aspects, environmental aspects, if you like.

But the important thing is a 1 percent improvement in efficiency, any efficiency improvement you can get in the existing 500 gigawatts of coal-fired power plant, would have a huge effect on the RPS for those states that have those power plants. So efficiency improvements at the same time that you consider cofiring and optimizing the thermal process is a key secondary that should be considered as we go forward revamping installed base.

At the bottom of this chart we talk

about CO_2 or sequestration, carbon sequestration. And I suppose just a side note, it's a nice discussion. I think it's a nice demonstration project that's going on in the country at the moment. There are various ways of taking CO_2 and separating it. And there's only one way to store it that we've found, and that is underground.

And the costs associated with that right now I don't think any subsidy or stimulus program could actually afford to pay for them. So we don't see that as a large-scale solution at this point in time.

I wanted to talk a little bit about the biomass supply chain. I think the Forestry Service did a good job of that already. So I will be brief.

But, of course, your forest reserve, starting at the top of the chart, end up in final end use products by consumers at the bottom of the chart. And really break down into either fuel wood, sawlogs, residues, or in pulp wood. And, of course, the pulp wood ends up in the paper industry. The sawlogs end up in the furniture and manufactured good industry. And the fuel wood ends up in the energy production side.

And if we look at that supply chain in a little bit more detail, the next chart tries to give you some of the filters that go from the extreme left, which is the forestland, filters down first of all into grades that are less than 30 percent slope. It's very difficult to look at secondaries in slopes greater than 30 percent. And that then goes into timberland or in other forestland.

And important aspects on the right-hand side is to consider the unmerchantable, low-use wood, two areas from either the timberland or from other forestland. And that is the woody biomass that we're talking about, to burn, to cofire to replace coal.

The real target to make cofiring much more viable is to make the biomass location agnostic. Today most of our studies revolve around taking woody biomass and locating it within a 100-mile radius; and then determining which plants are in that radius, and which power plants could be cofired as a result of location.

If we could break the location barrier and make biomass location agnostic, it turns into much more of a commodity. But these are the kind of studies that are being done by a number of utilities now to see where they could actually source their biomass within a 100-mile radius.

As a result we've got a little bit of tourism on the lumber mills and the locations of these lumber mills. Various types of lumber mills from the chip composite and plywood, also down to pulp and sawmills. I think the sawmills is certainly one of the best locales to gather biomass woody product for cofiring.

The pulp and paper industry, of course, has a significant source for biomass and cofiring. And this map shows a significant number in the state of California.

And of course, as a result of that, you can see a number of combined heating and power facilities utilizing biomass. And I think, as previous speakers have mentioned, a significant number of those, also, in the state of California. And need to be continued to keep viable.

Biomass potential. This is an interesting map. It kind of gives you, if you were to look at the thermal or the electrical equivalent capability of biomass in each state, the percentage shown in each state gives you an idea of how much of the current consumption of electricity in those states could be actually replaced with a technical potential of biomass.

So, for example, the readily available biomass for cofiring in the state of California, already 14 percent of the total power generated in the state of California could technically be replaced with the biomass heating potential, thermal potential.

And now for the fun stuff. We mentioned I was going to talk a little bit about woody biomass. And I think we have some samples. There is a reason why I'm wearing black. Please don't get too dirty touching it. But I thought it was good to talk about what is woody biomass. What does it look like when it's torrefied.

And unfortunately I don't have examples of pelletized biomass, but the torrefied product is certainly something that you can probably smell from here. It smells like a wood fire. And it's an interesting process, because, you know, it's really a roasting process.

And the best way to describe torrefaction is really what we do with coffee beans. And they really are roasted to a point where you do not damage the carbon calorific value. And so, you know, any fibrous biomass can be torrefied in a similar fashion.

And this table gives you an overview of at what temperatures do you do a drying function. You can see torrefaction takes place between 140 and 350 degrees Celsius.

And then you can go through a devolatization process, a gasification, and finally combustion at about 800 to 900 degrees Celsius.

ASSOCIATE MEMBER BOYD: I may be getting ahead of you, but what kind of costs does this add to the process?

MR. SULLIVAN: I think we come up with a break-even analysis on cost. Let me come to that in a little bit; you are a little bit ahead of me.

ASSOCIATE MEMBER BOYD: All right, wait till you're ready.

MR. SULLIVAN: I think the important thing is transport factors. And the reason why you do this torrefaction is really to make it transportable. You've obtaining factors in density. And you're really taking what is a natural process of wood over 60 billion years, and in 60 seconds you're creating the exact same product that you have in the way of coal without the compression.

So it's really taking nature's natural process and without the compression and the time factor, producing what I could call a virtual coal. And as a result the calorific value of that is high. It's easy to pelletize. And operators of power plants like the look of it because, as you can see, it looks like coal. It has, I think, a calorific value almost equal to coal, about 20 percent short of the same Btus per tonne that coal has.

ASSOCIATE MEMBER BOYD: It's a very high temperature. What's the fuel used to do this?

MR. SULLIVAN: It is actually an endothermic process. When you torrefy it -- actually I've got a diagram coming. The process itself is fairly simple. It's not high technology, itself.

This is an example of a 60 tonne per year production facility, and there is a combustor. And, of course, when you combust any wood product you obtain heat. You also obtain a syngas, a certain amount of syngas even at 300 degrees C. A lot of that gas is rerouted back into the burners to heat.

And I would say, you know, I wouldn't say it's closed, you do have some emissions. But essentially you're recycling a lot of the heat that you get out of the torrefaction process internally.

And what's most important is that the 40 percent moisture that is typical in biomass is eliminated totally.

On the cost elements I think we found that at 20-mile radius the cost of delivering woody biomass is at a break-even. In fact, it goes exponentially up on woody biomass with respect to a torrefied woody product.

So at 20-mile radius it's actually better, from a cost point of view, to torrefy the biomass than to leave it in its state, and that's because of the transport costs. That was the break-even point that most of our analyses have shown.

So the next section was really to kind of summarize the technical potential, and guesstimate, if you like, the real potential in biomass power, particularly for the state of

California and the RPS.

And, you know, we've covered the fact that the selected WECC regions is around about 33 gigawatts. Of course, if we 100 percent biomass fired that, technically you'd have about 10 gigawatts of coal units that effectively feed California WECC regions. Within California, itself, only about half a gigawatt.

But if you were to look at a percentage of coal firing, which is more realistic, 10 or 30 percent, we reckon approximately 1 gigawatt to 3 gigawatts of biomass power could actually form a fuel switching or replacement for the state of California.

This table actually is probably far more relevant if you look at the 22,230 sales that took place in gigawatt hours. These are actual out-of-state contracting sales to the state of California. And if you were to take that 22,000 gigawatt hours and look at maybe even a 10 percent, you'd be then looking at about 2000 gigawatt hours of renewable energy by renewing those contracts and forcing those power plants to cofire.

So, just a brief summary of the issues

and challenges. Of course, I think maximizing job creation, number of people in the low-income area would love to be out there clearing forests and collecting wood. And setting that into nice modular torrefaction/pelletizing plants, making the product a commodity and transportable.

So the infrastructure for a biomass transportation, I think, is the key issue and the key stumbling block that we see today.

We believe that a construction of torrefaction and pelletizing plants throughout the country would be a great way to make the commodity and open up the biomass and cofiring market.

And if you did the second bullet, you wouldn't have the operator challenge. Most operators do not like burning wood product in their boilers. For years and years they've tuned the power plants to work on certain coal with certain Btu and pollution content. And so they're very resistant to any percentage of cofiring unless it's torrefied, which is essentially the same as coal.

So we have that challenge, and there's no real incentives right now, other than the RPS, but no real economic incentives until the carbon tax or the penalties are real.

The torrefaction process, I think, is a good solution, but you will see that we still have to address siting issues, and we still have to address pollution issues. So we have to extract the potential for the low NOx and the SOx from the biomass firing. But we also, in burning anything in a coal-fired power plant, you also have to address the SCR and potential flue gas constituents that can cause fouling of SCRs.

A lot of that experience already exists in Europe. A lot of plants are already doing a lot of this in Europe. In fact, some of them are forced to. And some of them are also forced to, in a must-run capacity, in the sense that if you have any biomass or any renewable energy in Europe, it changes the equation when those must run. Which means all other units back down. It's a very interesting change in the operating philosophy.

So that really covers a short interlude at the end of the day. I'm now the only one stopping you not from your lunch, certainly not from your biomass.

ASSOCIATE MEMBER BOYD: You're just

keeping Commissioner Byron and I from our next meeting of the evening.

(Laughter.)

ASSOCIATE MEMBER BOYD: Actually, that was very interesting. I don't know if I'm willing to confess in front of this audience, I've studied biomass for more than a decade. And today's the first time I've ever heard of torrefaction, torrefaction. Amazing. You learn something every day.

MS. BROWN: Yes, --

MR. SULLIVAN: I hope you had a chance to touch it.

PRESIDING MEMBER BYRON: We discussed this last week in our cost of generation workshop that Mr. Sullivan was at.

ASSOCIATE MEMBER BOYD: I avoided that.

(Laughter.)

ASSOCIATE MEMBER BOYD: I was probably somewhere else in the state.

MR. SULLIVAN: Well, please feel free to take the samples with you. Do not digest.

(Laughter.)

ASSOCIATE MEMBER BOYD: Actually I was looking in the audience as you were speaking, for somebody who's left, but there's a plant proposal in the Tahoe Basin that's kind of a poster child of mine. I almost wish those folks -- or I intend to ask them about this torrefaction process, because this sounds interesting.

PRESIDING MEMBER BYRON: Well, you've given us some really good ideas, Mr. Sullivan. Thank you very much for that presentation.

MR. SULLIVAN: Thank you.

MR. ORTA: We received this comment this morning. Is Michael Hawkins from Millenium Energy still here?

MR. HAWKINS: Yes.

MR. ORTA: Please come to the podium.

MR. HAWKINS: Good afternoon. I'm actually surprised that at 4:30 in the afternoon there's anyone left in the room to talk about anything related to coal. So, fascinating.

ASSOCIATE MEMBER BOYD: Coal may have driven some people away, but this has proven to be --

MR. HAWKINS: I'm sure it has.

ASSOCIATE MEMBER BOYD: -- more interesting than some of them might have thought.

MR. HAWKINS: Millenium Energy has a 50

megawatt coal and petroleum coke and TDF, tire-derived fuel, in Kern County near Bakersfield. And we also inject steam in the ground for enhanced oil recovery. And have been operating there since 1989. And we are in the process of converting that facility to biomass.

I can respond to the earlier comment that probably no self-respecting coal plant would voluntarily convert to biomass unless incentivized or forced to.

ASSOCIATE MEMBER BOYD: Well, the difference is you're in California.

(Laughter.)

MR. HAWKINS: That's exactly right, which is why I'm here today.

The process of converting is not easy; difficult from a permitting standpoint. Also economically. And to convert entirely to biomass does require a significant modification, not the least of which is the cost of fuel handling.

The biggest challenge of cofiring, and by the way, we are currently cofiring in our facility; we burn approximately 25 percent biomass, cofired with our coal, which comes from Utah.

The biggest challenge is that the two fuels are substantially different; and the handling characteristics of those are very different.

So, as you increase the quantity of biomass, it adds challenges if you are an existing coal facility. The equipment is designed for the free flow of coal. And as you inject biomass you reach a certain point where the fuels do not blend, and pluggage occurs.

And then as you burn those in a combustor the combustor characteristics are very different of the two fuels. Biomass obviously much lower. And as large chunks of that flow through the system, there are environmental problems, challenges with SO_2 and NO_x and CO.

So, some of those challenges exist.

The cost. Historically the cost of coal has been much lower than biomass. Coal contracts are typically for ten years or 20 years, so it's easy to know, out in the future, exactly what the quality of fuel will be, where it will come from, what the price will be. Biomass poses a challenge in terms of long-term contracts and knowing for sure where that fuel will come from, and what the price of that product will be.

But the incentives, in California especially, for renewable fuels are substantial, which will motivate a number of people. Opportunities in California for that are limited. As indicated, there aren't very many coal-fired plants, cogeneration plants or others, a few cement plants, but there are some.

The good news is that the technology that most of the coal plants use, these plants have been built over the last 20 to 25 years, the technology is very flexible. And these boilers, especially circulating fluidized bed boilers, but others of various technologies, will burn a variety of fuels, and somewhat efficiently.

So most of the capital improvement is related to the handling of the fuel, and not the combustion of the fuel. There are some dollars required in the combustor to modify how it's injected, how it's handled. But most of the expense is in fuel handling.

To modify a coal plant to burn 100 percent biomass is capital intensive, and requires substantial modification. But cofiring up to 20 or 25 percent does not require a lot of modification.

The problem is you are limited to the types of biomass you can burn. If you're burning very uniform shells or 2-by-2 inch chipped material, it's a fairly uniform product and it blends well.

If you go to the more popular, what's called the hog fuel, which is more shredded than it is chipped, it plugs the coal equipment. And so you can't blend that type of product into an existing coal silo.

Coal plants in California don't take up a large footprint, unlike biomass projects. So to convert a biomass project to a biomass project it requires more real estate, mostly just for the receiving, the storage, the handling of the biomass fuel.

Coal, by permit requirement, was placed into a smaller footprint, covered, sealed. The coal typically is not exposed in the handling process.

So as that material comes in, if you're blending a small amount, that's merely added three trucks of coal one truck of biomass. And then, again, you have to monitor that, because as that one truck of biomass flows through the system, goes into the combustor, there can be spikes or substantial changes in the combustion characteristics.

I have lots of other information I'd be happy to share, but otherwise, if there are any questions, I'd be happy to take them.

ASSOCIATE MEMBER BOYD: Well, thank you. I'm very pleased to hear you're doing what you're doing. That's a plus for California. I don't really have any questions -- well, I will ask a question about torrefied fuel. Have you considered that? I bet you you knew what it was.

(Laughter.)

MR. HAWKINS: Yes, I do, and pelletized. We have considered it. The cost is prohibitive. Pelletizing and torrefying, although technically sound, adds substantial expense to an otherwise fairly expensive process.

ASSOCIATE MEMBER BOYD: I wondered about that. Thank you.

MR. HAWKINS: I can also tell you that the surrounding areas, having come from a large utility in my former life, I do agree entirely with the statement that large coal plants are very reluctant to inject other fuels, especially biomass.

Coal plants tend to be large, 1000 megawatts, for instance. A 1000 megawatt coal plant would require 8 million tons a year of biomass. And if it were just 10 percent of that, that would be 800,000 tons of biomass. That's a very large quantity. So the handling challenges of that would be --

PRESIDING MEMBER BYRON: And they're grouped. They tend to be in groups of larger than one coal plant.

MR. HAWKINS: Yes.

PRESIDING MEMBER BYRON: Mr. Hawkins, I missed the point. Why is it that you're converting to biomass?

MR. HAWKINS: AB-32, 1368, other pieces of legislation in California have basically driven us to the point where a coal plant is no longer viable --

ASSOCIATE MEMBER BOYD: You're polite in calling it incentives. I was thinking of the disincentives we have in California for continuing with coal.

MR. HAWKINS: Yes.

ASSOCIATE MEMBER BOYD: I will comment, only a comment, that cofiring biomass is something that I know more than I ever wanted to know about, based on a project that I cochaired a couple years ago with the Western Governors. That actually was about transportation fuels, but I didn't want to cochair it. The Governor's Office twisted my arm. I said, look, there are coal states in the west, we're going to have to deal with coal, et cetera, et cetera. And sure enough, we did.

But from a professor, Robert Williams, from Princeton, who was a member of our working group, I learned all I ever wanted to know about cofiring biomass with coal. He's a huge proponent of that.

Anyway, we debated it at length. And, you're right, the coal states were not anxious to embrace the idea of cofiring for all the reasons you said. There's two basic coal states in the west, Montana and Wyoming.

But it raised a question in my mind then that came to mind during the KEMA presentation, but I didn't ask it. And you touched on it. And that is it got to the point where I began to think that there was more competition, potential competition for biomass, as a fuel, than there was going to be biomass, even though we have a lot of it.

Cofiring coal plants versus turning that biomass more directly into electricity versus turning biomass into gaseous or liquid fuels, there's suddenly a lot of competition for biomass as a fuel. Now economics may make the decisions for people.

But anyway, it was an interesting question, and it still lies there. And I just wonder if anybody has wrestled with all the demands on biomass versus the supply. But maybe at a future time.

PRESIDING MEMBER BYRON: Mr. Hawkins, thanks for coming, and thanks for making your investment here in California to convert to biomass. Look forward to hearing more about how the project proceeds, and how successful it is.

MR. ORTA: Mr. Hawkins, if you'd like to provide more information and/or elaborate on your comments, if you'd please file written comments by May 5th.

We don't have any other commenters on WebEx.

PRESIDING MEMBER BYRON: So I take it we're done?

MR. ORTA: I believe so.

PRESIDING MEMBER BYRON: Commissioner Boyd, closing comments?

ASSOCIATE MEMBER BOYD: All I would say is I found this very interesting. I regret having missed a couple of presentations due to the fact that we have so many demands on us now that it's hard to sit still for a day. It's almost you have to leave town not to have multiple demands made.

But in any event, I found this, as always, very interesting. I'm still frustrated over lots of the issues that have been issues for many many years. And I'm hoping to see that the pressure of a lot of what we're dealing with today maybe provide a greater forcing function on getting some solutions.

And I'm not running for another term on this board, I'm not running for office, I'm not running for anything, and so maybe I can get pushy and obnoxious about solving some of these problems finally.

So, anyway, it's been most interesting.

PRESIDING MEMBER BYRON: I agree. And,

in fact, I was a little bit surprised at the level of participation that we had today. So, don't feel badly, Mr. Orta, if we've been a little bit long. I think it was very worthwhile, a well put together workshop.

I'd like to say to the folks that came, and excellent presentations and comments that we got, I certainly got a much better sense of the pain that you all feel. It seems to me you deal with a lot of the same issues that natural gas and the combined heat and power industry feels, as well. But, more.

And I was certainly taken with the comment about cross-agency purposes. It would seem to me that we have a number of laws that the various agencies are required to fulfill. We have special laws, too, as I've come to find out.

And there's a number of issues that are upon us that even make it more complicated, such as the priority reserve concerns and the challenges down in the South Coast. And the presentation that we got from the San Joaquin Valley Air Pollution Control District definitely showed that it's not confined to that part of the state, either.

We must solve this dilemma for a number of different reasons. I was reading some new legislation that's been introduced, just last night I was reading it. I think it's fairly new. On the South Coast priority reserve issue.

Senator Wright has introduced it. I can't remember the bill number right now, but it's clearly geared towards solving this same kind of problem in South Coast for natural gas. And I think maybe we need to look at similar kinds of approaches here. And I plan to discuss that further with Commissioner Boyd.

We certainly ought to be able to get these conflicting regulations sorted out in order to make biopower more successful in this state.

I appreciated the comments that helped clarify what some of those problems are, namely cost and the access to fuel. But there's others. There's the, you know, there's moving forward in the feed-in tariff, and standardizing the agreements that -- the power purchase agreements; and perhaps eliminate the MPR interconnection problems.

I just can't understand how we can flare renewable fuels because of our conflicting regulations. And dealing with the NOx concerns that come from the controlled combustion of fuels, generation of electricity versus the uncontrolled combustion of these fuels that take place when wildfires strike.

So, I think I'll stop there. I've learned a great deal today. Commissioner, I look forward to working with you on recommendations that we can make in the IEPR, and perhaps taking the lead with some of our fellow agencies that were pointed out to us when you weren't here today, that are not present.

And I'd like to thank all the staff and all the participants. I'm reminded that tomorrow is earth day. You know, it's like mothers day is around the corner, when you're supposed to remember your mother. Tomorrow's that day when we're supposed to remember the earth a little bit.

And so it's certainly fitting that we're discussing biopower today, because this is a much more substantial source of power that's being under-utilized in the state. We need to get it figured out.

ASSOCIATE MEMBER BOYD: Mr. Chairman, I am very gratified by your statement. With regard to finding another Commissioner now well educated on this topic, and knowing all the issues and problems, and some of the economics.

For years we've been trying to drive all the disparate parts of the biomass equation into a single tent where we could balance the economics. Because there are an incredible number of social benefits. The trouble is they don't generate cash that allows you to move them right away to pay for the investments we need to make.

You know, I've always grieved the amount of money we've spent fighting fires in this state when we could get some of the fuel out of the forest, et cetera, et cetera. But, you know, maybe together we can move this subject.

I'm glad to hear your comments. And I look forward to working with you. So, there's hope.

PRESIDING MEMBER BYRON: Good. Thank you. Thank you very much for being here. We'll be adjourned.

(Whereupon, at 4:59 p.m., the Joint Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 19th day of May, 2009.