COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
)
Preparation of the) Docket No.
2007 Integrated Energy Policy Report) 06-IEP-1O
Energy Policy Report)
)
Clean Coal Technology and Carbon)
Dioxide Capture and Storage)
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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SACRAMENTO, CALIFORNIA

TUESDAY, MAY 29, 2007

9:09 A.M.

Reported by:
Peter Petty
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COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John L. Geesman, Associate Member

James Boyd

Jeffrey Byron

ADVISORS PRESENT

Melissa Jones

STAFF PRESENT

Art Soinski

Kelly Birkinshaw

ALSO PRESENT

Stu Dalton
Electric Power Research Institute

George Peridas
Natural Resources Defense Council

Lawrence Kostrzewa
Southern California Edison Company
Carson Hydrogen Power, LLC

Michael Mudd (via Webex)
FutureGen Alliance, Inc.

Tom Kaiserski
Office of the Governor
State of Missouri

John Gale (via Webex)
International Energy Agency Greenhouse R&D Programme

Larry Myer
West Coast Regional Carbon Sequestration Partnership -WESTCARB (CEC and LBNL)

ALSO PRESENT

John Kadyszewski
Winrock International

Leonard Devanna
Clean Energy Systems

I N D E X

I N D E X

Page

P R O C E E D I N G S

9:09 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is a Committee workshop of the Integrated Energy Policy Report Committee. I am Jackie Pfannenstiel; I am the Presiding Commissioner on that Committee. To my right is Commissioner John Geesman, who is the other Commissioner on the Committee. And to his right is his Advisor, Melissa Jones.

We are joined by two other Commissioners. To my left is Commissioner Jeff Byron. And to his left is Commissioner Jim Boyd.

This subject of clean coal technology and carbon capture is critically important, very timely, and something that I think we're all dealing with in many aspects of the energy policy that we're considering for the IEPR this year.

We're going to hear, I think, several different areas of the technology development that will feed into a lot of what we're doing.

With that, do we have opening comments from the Commissioners? Nothing. Why don't I turn it over to staff, then.

MR. SOINSKI: Good morning,

Commissioners and guests, participants. My name is Art Soinski; I'm with the California Energy Commission; I'm one of the organizers of this workshop, especially the morning session. Kelly Birkinshaw, who is in the PIER environmental group is the organizer of the afternoon session.

There's a lot of relationships between the morning and the afternoon. The morning is going to focus on clean coal technologies; and the afternoon will focus on capture of carbon dioxide and sequestration. But there will be some overlap back and forth between the two.

There is a panel discussion at the end of the morning session, which hopefully will become a wrap-up for the morning, and will lead on to the afternoon session on sequestration.

A couple of housekeeping items. If you wish to speak there are blue cards which are on the table just inside the doors. And if you bring this up here we'll take these to the Commissioners.

I apologize for the fact apparently the agenda was posted, but I'm not sure where it was posted on our website. I couldn't find it this morning. Tried to figure out why I got calls from people wondering when the workshop was going to end. And I'm sorry for that. But there are printed copies now available at the back.

It's a pretty busy schedule. We have five speakers in the morning, one of whom is going to speak remotely via Webex. And are there any questions about the aspects of the agenda?

I've just been notified that this is being broadcast via Webex, so if you do make comments those comments will be recorded.

The first speaker is Stu Dalton from the Electric Power Research Institute. Stu is a graduate of the University of California at Berkeley in chemical engineering. He has been with the Electric Power Research Institute since 1976. He is the Director of Generation sector at EPRI. He's been involved in clean coal and emissions work for his career. He's testified before Congress. He's a very busy man. He's appeared in many different organizations. He appeared at our 2005 Integrated Energy Policy Report workshop on clean coal.

We're very pleased to have him here. Stu.

MR. DALTON: Thank you, Art, and,

Commissioners, ladies and gentlemen. I'm here to chat a little bit about clean coal in the morning, and then carbon capture in the afternoon. So you get two doses of me; I apologize for that in advance. And I'll try and make sure that I can keep this fast-paced; and I'll be happy to answer questions, as well.

I'm going to cover this morning a little bit of background on the technology without, one of the first acronyms, carbon capture and storage, CCS. A little on the status of the economics and description of it; as well as an international perspective on clean coal.

I happen to be involved in the Asian Pacific Partnership; I'm the U.S. rep for the Asian Pacific Partnership from the industrial sector, and have been involved in a number of international activities, including EPRI's own work in that area.

Just as a reminder, up in front of you on the dais is California's home-grown solid fuel; literally it grows. From the oil, as you, in effect, take and add hydrogen and upgrade oil to the best possible products the stuff that's left sits in front of you. Petroleum coke. And that's why I put the petroleum coke in the one area that it exists. It also exists in the San Francisco Bay Area; up in the Washington refineries; and a number of other places around the U.S.

But, of course, one of the early applications that has been proposed for carbon capture and clean coal, in quotes, is the Carson project, the clean hydrogen from coal -- pardon me, clean hydrogen and power project.

There are a number of other coals. I'm going to talk a little bit about some economics with a bituminous coal. And notice that not too far from California are some significant bituminous resources. The grey areas are shown as bituminous coals. The very large deposits,now representing about 50 percent of all coal utilized in the U.S., from the Powder River Basin, another major area. That's the second acronym of the day, PRB, Powder River Basin.

And then there are other large coal fields across the U.S. The U.S. is one of the dominant countries as far as the resource in the ground. Of course, that's been one of the reasons why coal has been relatively less expensive than natural gas and oil in the U.S.

Our messages from today would be that a portfolio is needed for the future. Certainly right at the top of the portfolio, the same thing that's at the top of the Energy Commission's portfolio, on end use and efficiency, also renewables: nuclear power, generation efficiency and improving that generation efficiency, as well as CO_2 capture and storage. We believe they're all important. We believe that efficiency improvements can be improved in the short term and reduce CO_2 emissions per kilowatt from say 5 percent now to what we believe is on the order of 20 percent per kilowatt hour over the next 20 years.

We believe no coal technology is preferred for all coals, elevations or altitudes and site conditions. There's quite a bit of difference in technology.

And we've been developing a effort that we have term coal fleet for tomorrow, developing design guides for clean coal with and without carbon capture. We've been doing that for the last several years.

Just to give you a visualization of what's been added in the U.S. in the last about eight years, and what's projected with some reasonable assurance that this is a serious project; it's not just every announcement.

But you can see the green; the dark green being combined cycle and the light green being combustion turbines. With the peak a few years ago now declining because of the increased cost of natural gas primarily on an overall U.S. basis. You can see some retirements below the line and you can see very few megawatts of anything else. Until the 2004/2005, and then you can start to see a few megawatts of other technologies coming in and projected. The 2007 nuclear megawatts are addition in TVA service territory. But it's a single set of plants being added.

You can see wind and other, primarily biomass related, showing up at the top.

PRESIDING MEMBER PFANNENSTIEL: Stu, let me just say --

MR. DALTON: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- these are announcements, or are these actuals through '07 and announcements thereafter?

MR. DALTON: It's actuals through '06.

And we haven't got the full actuals through '07 and thereafter.

PRESIDING MEMBER PFANNENSTIEL: So they're announcements, but not intended to go online for some years later?

MR. DALTON: These are the commercial operating dates. So, these are when the different megawatts came into commercial service in each year.

PRESIDING MEMBER PFANNENSTIEL: So in 2007 we have the TVA nuclear plants coming into service?

MR. DALTON: Correct. They just are coming in this year.

PRESIDING MEMBER PFANNENSTIEL: Got it.

MR. DALTON: And now, of course, you have different numbers out in the future, you have projections. What we've done is we've assigned some weighting, so it's not just a commercial announcement, but that there is some action, permits have been applied for, there's something realistic about that. That doesn't mean all of them will come to the future into operation, say, in 2011, 2012, 2013. So there certainly is some speculation in there.

We update this periodically. It's a way to give you some idea of the balance. And what you see is coal, because of its price is starting to dominate a lot of the new announcements. That's not all there is out in the future.

And recognize, too, that you don't have to announce a combined cycle or a combustion turbine seven years in advance. You can build it in a shorter time than that, so that's one reason why there's nothing shown for 2013, 2014 or 2015 for combustion turbines or combined cycles. Just to put that in perspective.

But you can see there's quite a bit of coal now being proposed. Now, there's a lot of question of what is clean coal and how do you clean it. I used this diagram two years ago. It's still illustrative because it gives some pictures of some reality, as well as some indication of how the emissions, except for CO_2, are controlled.

You can have the coal with either a higher sulfur or a lower sulfur. And that depends on the source primarily. You can also clean it. So there is getting a low-sulfur fuel.

You can then change the way it's burned.

The fact I started my career working in emission control in California here in the early '70s. Actually working on NOx control by combustion control; controlling the temperature and mixing controls the amount of NOx that's formed.

And then you put a catalyst, much like we have both on automobiles and in the back of combined cycle plants, to reduce, using a selective catalytic reduction, the NOx even further.

Catching the particulate can be done through fabric filters or precipitators, electrostatic precipitators. And then SO2 can be caught in chemical reactions in SO2 scrubbers. What's been done recently nationwide is some fairly large investments, something on the order of $50 billion of investment in emission controls from existing plant to meet the new requirements that are coming in nationwide.

So there's a lot of activity in either upgrading or installing emission controls on a variety of plants for both NOx and particulate and flue gas-to-sulfurization. So these are being reduced nationwide.

Newer plants can have very low emissions even on a pulverized coal or ground-up. You take that block of coal and you grind it up about the consistency of face powder and then burn it. That is the fundamental burning mechanism for coal.

Gasification combined cycle, just to point out, this is where you have the chemical plant on the back end of a power plant. When you put the chemical plant on the front end of a power plant that's where you get so-called gasification combined cycle. Another acronym, IGCC.

Where you take air, separate out the oxygen; typically uses oxygen and coal; makes a vitreous looking slag. Looks like obsidian, somewhat similar in color to the black, but looks glassy.

Then you clean up the gas using a variety of different chemical reaction acid gas cleanup technologies. And now what you have is relatively clean, very clean actually, CO and hydrogen primarily; little bit of few other things like methane.

That's then the fuel for the combustion turbine. Now when CO is burned, it makes CO2. And so without capture this is what a gasification combined cycle looks like, and the exhaust gas contains CO_2, much like a natural gas fired plant. Then you have heat recovery, of course, in the last stage.

There are some new ideas being developed. One of them that's been proposed is that if I, instead of burning coal in air, if I burn it in pure oxygen I have primarily CO_2, plus any constituents that need to be cleaned up.

And so one of the ideas generically represented up at the top is a boiler that now recirculates a little bit of that CO_2, burns in a stream that has quite a bit of CO_2 in it; and makes a relatively pure stream of CO_2. That's been cleaned, and the idea is you then just compress it. You should be able to store that CO_2.

California's own Clean Energy Systems, and I hope they don't mind I borrowed their logo, at least I recognized them here, so. The Clean Energy Systems folks have one version of oxyfuel operating here in California. They've used methane, or they can use clean syngas, synthetic gas, meaning CO and hydrogen, plus oxygen, giving CO_2 and steam as one of their cycles that they've been looking at.

So there's several different versions of oxyfuel that are out there proposed. These are being developed, scaled up at this point.

If you look at an overall technology deployment curve, and this is a curve that I believe Rand originated many years ago; Bechtel borrowed it from them; we borrowed it from Bechtel. So the idea of the curve is for any technology, a microchip or a new power plant.

Now, the time scale varies quite a bit. It takes a lot less time to develop a new microchip than it does to develop a new power plant, both with siting and others. So the time scale here is for any technology.

And when you start out with the new idea people tend to think it's going to be cheap and easy. And it tends to develop that there are more problems, more costs associated with a new technology than you originally envision. So that's why the curve goes up first before it comes down.

Carnegie Mellon has recently put the data toward this for the power industry. And it's a curve that somewhat replicates this shape.

The points here are that there are

different stages of development. And many have a ways to go yet before they're fully developed, tested and demonstrated. The idea that research and development stage for certain types of very high temperature advance, yet another acronym, ultra super critical pulverized coal plants, and that's not the University of Southern California. That it's advanced coal plants, that spans quite an area. Because there is some super alloy development that actually EPRI manages for the U.S. Department of Energy that is still ongoing to develop the very highest efficiency plants.

Then you can see CO2 storage still going through research and development stage. We're getting to the demonstration stage soon.

Oxyfuel, as you can see it at various stages of research development. CO2 capture varies quite a bit because there's been quite a bit of work that's done on the concept.

Now, IGCC plants, you can see, have been demonstrated at full scale without capture. And so they're starting to come down the curve. Ultra super critical PC plants at modest temperatures have been built worldwide. And then super critical PC plants are in operation in many places including California for gas and oil. But only outside of California for larger scale conventional plant.

We see that the improvement in efficiency and the vertical axis here being CO2 reduction can be significant from conventional plant on through commercial super critical plant. And then advanced super critical plant.

The goal for the U.S. R&D effort and the European effort in this area is the far blue band.

Again, there's about 2 percent efficiency gain gives you about a 5 percent CO2 reduction.

Giving you a visualization that there are some IGCC plants out there producing power, the two that are talked about most are the two in the U.S., the Wabash, Indiana plant and the Polk plant in Florida. The Wabash is now a process owned by the Conoco Phillips Corporation. The plant in Florida, the process owned by GE. The owners of the plants, the Tampa Electric Company and Wabash Power are the two owners of the plants.

There's also a plant in the Netherlands at Buggenum and at Portiano at Spain. These are both Shell design IGCC plants.

There have been a lot of proposals. And this was actually sourced from the Gasification Technologies Council, not from EPRI. But there was a question that came up and I added the comment here at the top that there are a number -- you notice there are a lot of stars in the Illinois, Ohio and Texas area. And if you wonder why that is, in a number of cases, Illinois has very high sulfur coal; very hard to scrub all the SO_2 out of it. And so it's particularly good as a gasification coal. And that's one reason why there's so many there.

And Texas, there's some very poor quality lignites that might be useable, as well. And, again, they might be useable through that means. But there's also hydrogen and chemicals. If you think about it, that's where hydrogen and chemicals are produced, from natural gas. And so they have use for CO_2, they have use for hydrogen, et cetera.

But you can see, there's quite a few different types. Power, there have been a lot of proposals, not all of these will be built. But there have been a number of these that are undergoing design, permitting, et cetera.

Synthetic natural gas, the orange stars here. Hydrogen and chemicals, the green stars. The red stars are coal-to-liquids proposals. And existing gasification plants of various types.

This is a build slide showing the emissions from coal with and without CO_2 capture. So I'm getting a little into this afternoon with this. Pardon me, this is without CO_2 capture.

The new source performance standards, which are federal standards, have standards for SO_2, NOx and particulate from coal. If you look at the fleet average, this includes old units that weren't part of that subject to new source performance standards. And you can see the SO_2, NOx and particulate are much higher for the fleet average.

Mercury gets about 36 percent removal just with the natural removal in flash. And the CO_2 then -- mercury gets removal from flash and from any units that are scrubbed. And then the CO_2 is roughly 2250 pounds per megawatt hour. It's a useful number as you go across. And the water usage roughly 1200 gallons per megawatt hour.

If you run it across against a modern

plant with emission controls for a conventional super critical pulverized coal, a lot of the announcements are these, you can see the efficiency is higher. And the emissions lower. They meet or exceed the new source performance standard.

And here you've got both a -- two lines. One is for Powder River Basin and the other is for a bituminous coal. These are illustrative; they're not actual emissions on any site. But it gives you an idea of what the CO2 emissions are down at the bottom, the water usage, as well as the mercury reduction with a conventional scrubber on the back end of a power plant.

Ultra super critical pulverized coal, slightly higher efficiency, slightly lower CO2. Emissions about the same, because the emission control is about the same.

Gasification using a Conoco Phillips illustration. Efficiency about the same without capture. Emissions a bit lower; and lower, of course, than the new source performance standard, with mercury capture assumed in this case. You can put mercury capture in IGCC relatively easily. The existing gasification plant that has this makes some very mercury-sensitive byproducts -- or products, actually. And so they capture using a bed that's about as wide as my span, about six feet, and a little higher than I am. So it's a very small device done at high pressure. And it's a capture of mercury by that means.

Notice the water use here is less than for a conventional plant. And that's because some of the power comes from the gas turbine, not from the steam turbine. And the cooling water is not required in the greatest amount.

Natural gas combined cycle using methane or a natural gas with a selective catalytic reduction, and you can see the comparative emissions.

Just to point out that all the emission profiles are very low, especially compared to existing plant.

One of the big issues for the industry is that the costs have been increasing. That's not just for power plants, but for any chemical equipment. And since a lot of the power plant, either before or after the generation, is aimed at emission control, this is a chemical plant as well as a power plant.

And the construction cost indices for both chemical plant and general equipment has gone up quite a bit in the last few years. And so one of the points of contention is just how much these plants will cost.

Here is some publicly reported data that's gone to various PUCs and public filings. So, unfortunately, it's impossible to tell exactly what's in each of these cost estimates, because we don't have access to the proprietary data in back of it. But it is what's been reported in press and in public filings.

And AEP has said that their capital costs for new ultra super critical PCs ranges up -- and I've heard this might be a bit high compared to numbers, but the only public filings we've seen are the $2800 per kilowatt, down to about $1900 a kilowatt price.

Then Duke Energy has reported in their public filing to the Indiana PUC a $1,985,000,000 cost with a capital cost in dollars per kilowatt of about 3150. They have reported a ultra super critical comparative cost of about 2413 dollars per kilowatt.

NRG has reported at the $2400; and ultra super critical PC at $2400 for the Big Stone Plant. And a experimental new design that Southern Company has been reporting is 3000. None of these has carbon capture and storage included.

These are EPRI estimates, recently public estimates that are -- they have some interesting use. And now recognize this is Illinois number 6 coal, but again there are bituminous coals that are similar in their gasification properties, and in their burning and combustion properties -- they would be different in their emission properties -- in the western states.

But this is a standard gasification coal. And the first column here is super critical PC. And if you look at the red numbers at the bottom, the red bars, these are estimates of capital cost with no capture.

Then radiant quench, these are different, GE, Shell and EGas costs. And if you look at the additional cost of retrofit capture, that's in blue, or new capture, that's in green, these have had, in each case, a contingency added because these are novel processes. And that's the acronym first of a kind, FOAK.

So this shows some additional cost past the base estimate because we have seen some additional cost for first of a kind. Gasification also has first of a kind. We've seen some costs creep in those, so we've added 10 percent on those.

But this is all as ranges. You can see that the gap between conventional plant with capture and without capture is very large. The gap is smaller for IGCC. It costs less to add capture technology to an IGCC. But you're starting from a higher number. It's quite controversial as to how much higher that number is.

These are examples that EPRI has developed. And we see that the cost of capture is significant for either gasification or conventional plant.

Here's the equivalent for cost of electricity. And you can see that the gasification specifically one using a quench gasifier that's a good design for capture is less than pulverized coal in our projections, even with this contingency added for the cost of gasification first of a kind.

Now, when you boil this down and look at the factors that might impact the different types of coal, or the elevation, or different character of the coal, we see that for bituminous coal IGCC with CCS in most studies, not only our own, is usually favored.

That for lignite coal, which we don't have any in California or even close, you typically would not move it to California because it costs too much to move water and ash, that pulverized coal would be favored.

And in between you've got things that it's not quite clear. It depends on the exact character in our opinion. And different things like water use limits, lower elevation, lower moisture or lower ash might favor IGCC. Higher elevation, higher moisture, higher ash, higher ambient temperatures might favor a pulverized coal.

Just to point out that we've been leading a group of now 66 organizations from five continents, looking at advanced coal-based power systems. And thank you for the Energy Commission for sponsoring some of this work.

What we are doing here is learning by

doing to make sure we get the user requirements correct for the new designs, both with and without capture, for high reliability, near-zero emissions of everything else, and reducing the cost and the schedule of the new technologies.

We now have five continents; we still don't have anyone from South America or Antarctica, but we do have them for Asia, Australia, Europe, Africa and, of course, North America. About two-thirds of all the coal-fired capacity in the industry.

And then power producers, suppliers, rail, coal, engineering, oil companies, as well as governmental entities, are working with us. And many of the firms are helping to try and work together to make sure that we have designs that succeed right off the bat, and we learn from all the work that's gone on for the last 30 years around the world.

And the new designs are looking at capture and storage and integration of the design. This is a short list. I won't show this again this afternoon, but it includes California Energy Commission; it does include a number of organizations in this room, as well. And as you can see, quite a few manufacturers.

What we see next as an acceleration of industry efforts worldwide, we have been working with the Europeans. They're talking about some dozen installations with capture and storage.

The Africans are even looking at putting new plants in with space lift for capture and storage. So, it's become a worldwide phenomenon now, that people are looking at the options. We'll have more later on in the ways to deal with afternoon -- with CO2 this afternoon.

With that I'd like to finish. And if there are any questions I could answer now, or we could wait for the panel later on.

PRESIDING MEMBER PFANNENSTIEL: Are there questions now from the Commissioners?

COMMISSIONER BYRON: Stu, great to see you here. Thank you for coming. With regard to the funding of the program, the coal fleet participants, the Chairman pointed out to me an article this morning in The New York Times with regard to lawmakers pushing for big subsidies for coal process. And the coal industry has spent a lot of money on lobbying.

Have they spent much money in research

and development on carbon capture and sequestration?

MR. DALTON: There has been a fair amount spent in capture and storage, as well as in coal research. But, this is one of the major programs that the industry has funded. We have about $10 million a year that we put forward on developing these new designs.

We work in other areas on things like efficiency enhancement. So, our overall program can reduce CO2. But for capture and storage we have about $13 million a year, primarily funded by government -- pardon me, by industry; and very little funded by government in that case. And then there's the governmental programs, USDOE program, et cetera.

the people have been looking at gasification for some time. I know EPRI funded, I think, something like $70 million worth of the work at the Cool Water Consortium. That was what, two decades ago. So we've been involved for some time. The industry has been involved for some time. But it's not as much as the government entities have been funding, specifically the U.S. Department of Energy in some of the clean coal development.

COMMISSIONER BYRON: Are all the partners in as equal partners financially?

MR. DALTON: The ones that generate are proportionate to size. So they are larger. The ones with more of a stake in the coal megawatts have the highest payment. But folks like the ESKOM Corporation, for instance, has 32,000 megawatts of coal generation. Electricitie du France, which everyone thinks of as all nuclear, has some 20,000 megawatts spread out worldwide of conventional coal generation.

So they're big generators, and the U.S. big generators pay at that top level, as well.

COMMISSIONER BYRON: Thank you, Stu.

MR. DALTON: The Commission gets the lowest rate, by the way, because it doesn't have any megawatts of coal.

PRESIDING MEMBER PFANNENSTIEL: Or any money.

COMMISSIONER BYRON: Your presentation has provided a wonderful perspective on the cost differentials and how prices have gone up. Thank you very much for bringing it to us today.

MR. DALTON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: I just have -- following up on Jeff's question. I understand that the coal fleet for tomorrow is sponsored largely by the power sector. But I don't see, are -- the coal industry, itself, put money into it?

MR. DALTON: There's only one coal company that -- Commissioner, there's only one coal company that currently funds the work. I have been trying to get additional coal companies, but you see -- wrong slide -- Rio Tinto here, which has Rio Tinto, U.S. used to be Kennecott, and other organizations have been approached.

But at this point, the coal industry, per se, the suppliers of coal --

PRESIDING MEMBER PFANNENSTIEL: Right.

MR. DALTON: -- that's the only one.

PRESIDING MEMBER PFANNENSTIEL: All right, thank you. Other questions? Thank you very much. Excellent presentation.

MR. DALTON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: It looks like the next presentation is from the Natural Resources Defense Council.

DR. PERIDAS: Commissioners, ladies and

gentlemen, thank you. My name is George Peridas; I'm with the Natural Resources Defense Council. And I guess I somehow managed to get in without getting a visitors badge, so they must consider me a native Californian already. That's good news.

What I'm going to talk about today is two problems that we have, and I guess the latter is a problem because of the former. But it's not only, as I'm going to point out.

The first one is climate change. And the second one is coal. So what I'm going to try and do today is just start with giving you a bit of context about these two issues. And then towards the end talk a little bit about solutions.

It doesn't take a scientist to realize that the planet is warming. In his recent testimony, Al Gore in Congress, said that the planet has a fever. And I think he's right, if we look at the annual average temperatures dating back from the mid 1800s, there's a clear upwards trend.

And to reinforce these findings, the IPCC, the Intergovernmental Panel on Climate Change, earlier this year released its fourth assessment report which, I think, dissolves any doubts on the science of climate change -- well researched piece on climate science.

And there were some very clear statements in that report, and much less ambiguous, if they were ambiguous, in fact, than the previous version.

And what they said is the warming of the climate system is unequivocal, but it's very likely due to the observed increase of greenhouse gas concentrations caused by humans. That the increases in global air and ocean temperatures are real. That there is widespread melting of snow and ice. And there is rising global sea level.

This is not a report written by a bunch of hippie tree-huggers. The IPCC is -- this report is a consensus document by the vast majority of well renowned world scientists. And they were signed off by all (indiscernible) governments. So this really does represent an authority of documents.

And the skeptics do exist, and they do make themselves vocal every now and then. But really they are (indiscernible) and I would hope that people have realized that this is the case, that science has agreed on what's happening with the planet right now and the climate change is, in fact, real.

What does climate change mean? This is more or less quoted from the IPCC report. Warming. What does warming imply? Well, fewer and warmer cold days and nights. More and warmer hot days and nights. Heat waves; heat stress on humans and crops; increased insects and disease outbreaks; and fires.

It also implies droughts. That ultimately means reduced water availability, (indiscernible) lands, lower crop yields. Also heavy precipitation. Climate change essentially, global warming increases the amount of energy that's available in the atmosphere. And that causes or increase the likelihood and the frequency of more dramatic events. And this includes heavy rainfall which will damage crops and also lead to potential groundwater quality degradation. Increased cyclone activity; sea level rise and so on.

How much time do we have? This is a curve by Jim Hansen, who is Director of the NASA's Goddard Institute for space studies. And in a recent interview said that if business as usual continues then we'll be producing a very different planet. And he believes that the window that we have for action is no longer than a decade. So this problem really is urgent and we need to do something about it now.

Let me try and give you some numbers here to put this in context. The best estimates for the projected temperature rise by the end of the century in the latest IPCC report was between 1.8 and 4 degrees Celcius. The warming so far that we've experienced already has been about .7, .76.

What's considered safe in terms of allowed temperature increase to avoid what's called dangerous climate change is about 2 degrees Celcius. And we're already locked in because of inertia in the atmospheric system and the climate system to another roughly .6 degrees of warming. And that would be how much the temperature would increase if we froze emission levels at the value they were in the year 2000, which looks pretty unlikely to happen right now.

So, two degrees -- .76 we have already, and another .6 we've pretty much signed a contract with.

So what do we do? What is going to

happen to emissions? And how is coal related to that? Well, I'll take you through briefly. The DOE Energy Information Administration released its international energy outlook a few days ago. And I'm going to quote a few key statistics from that.

Will emissions keep growing? Well, if we don't change our ways and if we don't change what we do, then the answer is unequivocally yes. They're going to rise very sharply, and the majority of that increase is going to be due to coal. Also natural gas and liquid fuels will contribute to that, but as you see it from the coal line on the bottom right, that's going to contribute the majority of the emissions.

And the projected increase is for annual emissions from 26.9 gigatons in 2004 to 33.9 in 2015. And then it ramps all the way up to almost 43 gigatons in 2030. That's a large increase.

Are we sure that this will keep happening? Well, the answer is, again, yes. Even sensitivity to the scenarios project that the emissions will go up, even under scenarios of decreased economic growth, or very high oil prices, we still see emissions going up. And we definitely need concerted effort in some measures, policies and technologies to try and combat that increase.

Where will this growth take place? Well, you see the majority's going to be in the developing world. The blue line is ICD industrialized countries. The red line is non-ICD, which includes China and India and several other countries. And as you'll see there, the projected increase in emissions is much much greater than the industrialized countries that have done the damage, if you like, already and have emitted more intensely for several decades, or even more.

Should we point the finger? Well, I would answer no. If you look at how much energy is being consumed by a developing country citizen compared to a developed country citizen, then we're still greater than them by a factor of three or four.

So I don't think it is right to expect these countries that are now in the process of developing their economy and aspiring to a standard of living that would resemble ours, to expect them to shoulder the majority of this cost and say, okay, you have to reduce emissions; you know, we have been spewing these emissions out for decades. I think it's our duty to lead the way in terms of curbing them.

This is a closer look at coal specifically. At the moment it's fairly evenly split. In the future it's forecasted to grow, again, in developing countries much more. And China has huge coal reserves; and given how cheap they are, it will use them. And this is where the majority of the coal growth is going to come from. Nonetheless, we will see increase in the use of coal in the developing countries, as well.

The majority of coal use goes to electricity production. And you can see that from the right-hand graph over here. It's about two-thirds the amount of coal that's used in any other application.

If you look at China's coal, again there's a large projected increase from about 41 quad Btus in 2004; expected to more than double that to 95 in the next 25 years. This is a huge increase.

What about renewables? Well, they will grow, and the proportional growth will be very large. This is, I would like to stress, a business-as-usual scenario. And different policies and different state incentives might well change that.

But nonetheless, the point I'm trying to make with the slide is that, although renewables will grow in a business-as-usual scenario, this growth is mainly due to large hydro in countries like, in continents like South America, even Asia. The projected increase in coal is, again, much much bigger. So that puts it into context, you know, how much can we expect to come from renewables and how much can we expect coal to contribute to world emissions. And these are the two growth rates I was pointing out.

So what does this mean in terms of how much we're allowed to emit in relation to climate change? Well, the level that's been internationally recognized as safe emission level for carbon dioxide in the atmosphere is about 450 parts per million. Pre-industrial era we were about 218; now we're about, I think, 382 and growing. And we need to try and keep that under 450.

The IPCC said that to do that in the cumulative emissions during the course of the 21st century you need to be somewhere between 1370 and 2200 gigatons of CO2. And that was the latest estimate from a few months ago.

Assuming the growth rates on energy use, and also coal use, by the Energy Information Administration, and we'll see that we blow this budget very soon, between 2037 and 2051, and that coal use, itself, will blow that budget somewhere between 2064 and 2080. And I'm going to show you that in a graph. The green dotted line is the lower allowed limits for a carbon budget in the 21st century. And the top one is the upper bound. And the other two show the forecast emissions under a business-as-usual scenario.

And you will see that we cross the lower limits somewhere in 2037; the upper limit we exceed 2051. So essentially in half the allowed time. And coal use, itself, if we ignore all other emissions, will blow the budget in 2064, the low bound; and the upper bound in 2080. So we do have a genuine problem.

Coal is very carbon intensive. As I pointed out, it's use is expected to grow more than any other fuel. Its resources are vast and they're cheap. You know, the U.S. is to coal what

Saudi Arabia is to oil. And there are large reserves in China.

Coal is enjoying a strong resurgence, well, one because of the latest increase in oil and natural gas prices. And people, as Stu showed before, you know, they weren't thinking about building new coal plants, they were thinking about building combined cycle gas turbines and open cycle turbines. Now people are thinking of making very different investment decisions.

And also there's a -- I'm based in Washington, D.C. and we see that every day from various members of Congress and also a lot of states, to use coal in alternative applications like turning it into transportation fuels. And I will touch on this a little later on; explain why this is not a very good idea.

The point of this is we have huge coal reserves and we can destroy our climate and our planet well before we exhaust these reserves. So we need to figure out something to do with coal.

So, what about clean coal? Well, I don't much like that term. I don't think coal is clean in any way, shape or form. And what I'm showing here is not a Star Wars equipment; this is called (indiscernible) Robbins rotary bucket wheel excavator. And that's one of the things they're using.

The second one, trying to get rid of this logo down here, --

(Parties speaking simultaneously.)

DR. PERIDAS: All right. Okay. Well, this is an advert that showed up a few months ago and an interesting twist of friendly fire. These adverts showed up in the context of the TXU scramble down in Texas. And it turned out that the natural gas industry was backing them, which was a first. Because I think there was an unwritten law between industry not to go after each other. But clearly the natural gas guys were going after coal. But in any case, we don't think coal is clean.

This is an interesting slide that I got from an organization called ilovemountains.org. And it shows the impacts of mountains removal mining, which essentially blows up small peaks off mountains. And this is a GoogleEarth visualization of peaks that have actually fallen. And these guys are making a point that maybe we have to put up with some coal mining, but there are some ways of doing it that are totally unacceptable. And mountaintop removal is one of them. If you have a spare minute, go and visit that site. It's very interesting.

Coal is not inherently a clean fuel. There are mining issues that are associated with it. There have been several mining accidents. And China is also a country where these take place very frequently.

There are air emissions obviously associated with coal. These are acidic salts, and some of them are toxic; and some of them are related to mining. And there are also very large methane emissions that come from coal mining, itself. If you've heard of coalbed methane, some of that might be released when the coal is extracted. And methane is a very potent greenhouse gas.

There's water pollution that comes from mining activities and so on. If you want to take a closer look at these issues, I don't want to focus on them too much today, then take a look at the publication that we've issued a few months ago on that.

So, what do we do? Well, we need to be

pragmatic here, and we have two options. We don't think there's such a thing as clean coal, but the lights to have to stay on. So we can either pretend that coal will not be used, even though it makes up a good proportion, over half, of our nation's electricity production. And we have 200 years worth of reserves. And it's very cheap.

Or we can acknowledge the 800-pound gorilla in the greenhouse and say, well, we need to pursue all other opportunities as best we can; maximize energy efficiency and renewables first. And then insure that coal is only used as a last resort. And if it does get used, then we need to make sure in a comprehensive way that we minimize its adverse effects.

So, how do we do that? Well, the first step is clean up existing dirty coal-fired plants. And I'm talking about all pollutants here, not just CO_2.

The second one is don't use coal if you can avoid it. Maximize all the other measures first.

In terms of coal mining, NRDC is embarking on a joint initiative with a number of other environmental groups to research what the leading edge practices are in terms of coal mining. To make sure that industry do adhere to these practices. And this is not a means of endorsing coal mining, saying it's okay if you're going to mine coal. But we need to make sure that when it does take place it's done in the best possible way, using the best possible practices.

New plants, again, will have to be fitted with advanced pollution control equipments for SOx, NOx and mercury. And we don't believe the current targets for mercury are aggressive enough.

And finally, on the liquid coal fronts, this is a no-no for us. It's very carbon intensive. It's going to be extremely expensive. It's not an industry that can stand up on its own two feet without some kind of subsidy.

And you could say the same thing about renewables, but I think there's a very clear difference here that comes in. In a carbon-constrained world, these will be a huge burden on the taxpayers and also industry. And we don't want to see carbon prices being driven up by this very carbon-intensive industry. And we also don't want to see on-the-ground storage capacity for CO2 being taken up sooner than it should be, because these industries emit, or could emit, twice as much CO_2 as say gasoline or transportation fuels, diesel produced from conventional petroleum.

And finally, carbon capture and storage, sequestration. We can see reduce the greenhouse gas emission from coal, and we need to do that as a matter of urgency.

So, how do we do that? Let's have a quick look. You'll hear much more about this this afternoon. I'll just take a few brief minutes to go through that.

Carbon capture and storage, CCS, essentially means that you strip CO_2 from large point sources. And instead of venting it into the atmosphere you place it in geological reservoirs or formations underground where it can be expected to stay for a very long period of time.

This is not just related to coal. CCS can be used with other fuels, as well. It can be used with natural gas; it can be used with petroleum coke; it could even be used with biomass and actually result in a net reduction of emissions.

It is not a silver bullet. It's an

(indiscernible) technology. We should be trying other stuff first that's going to be cleaner and that's going to be cheaper. But given what we saw about the use of coal and other fossil fuels, we need to figure out a way to decarbonize them. And essentially what the problem is here is that we don't have the time to make the transition to these other measures soon enough to tackle climate change at the scale that's needed.

Has CCS been done before? The answer is yes, in several contexts. The three most striking examples of those are three major international projects. One is in Norway. And I actually attended a presentation last week where a delegate of (indiscernible), the Norwegian government was there, and it was very refreshing to hear from them to say that the Norwegian government has decided that it is not acceptable anymore to increase CO2 emissions. And I said, well, can you come to the U.S. and say that, please, because the situation there is rather different.

And they have a very concerted effort in place to reduce these emissions using carbon capture and storage. And they have very progressive policies to make sure that this technology is deployed soon enough and well enough. And they have, in fact, placed so much faith in the technology that any new power plant that does get built is going to have this technology.

But they're doing this already in the context of cleaning up natural gas, because its natural CO_2 content is too high. And they've been doing that since 1996 in Sleipner in the North Sea. And this shows the platform where the CO_2 gets stripped out of natural gas to bring it down to commercial specifications. And then it's injected several thousand feet underground in deep saline formation.

The other example is the Wayburn project in Canada. This takes CO_2 from the Great Plains -- Plant in North Dakota; and this is, again, a precombustion, if you like, application or similar technology to that. And then the CO_2 is pumped through a pipeline to the other side of the border to Canada, in Saskatchewan, where it is injected in an oil field in the Williston Basin for enhanced oil recovery, which is a way you inject CO_2 underground and you get oil that would otherwise be stranded or uneconomical to extract using conventional means.

And the third one is the In Salah project in Algeria. This is again a natural gas project cleanup. And this has been operating since 2004. And these are the three major examples of integrated carbon capture and storage.

Nonetheless, we have decades of relevant experience in related activities, and one of those is oil and gas exploration or extraction. I'll just mention enhanced oil recovery; this has been happening to a large extent on the Gulf Coast in Texas, Louisiana, and also the Permian Basin.

And in terms of transportation we also have over 2.5-thousand kilometers of CO2 pipelines that transport about 14 million tons of CO2 per year. You know, this is not Nobel technology.

There are also several research pilots and smaller scale capture and/or injection projects; there are tens more planned.

So, is this something wacky or can we be looking at real and safe emissions reduction from it? Well, the IPCC issued a special report on capture and storage about two years ago in 2005. And they estimated that the fraction of retained CO2, and I stress this, properly selected and managed geologic reservoirs is very like to exceed 99 percent over 100 years. And it's likely to exceed 99 percent over 1000 years.

What we're talking about is injecting CO2 in formations that have stored hydrocarbons, in some cases actual CO2, naturally occurring CO2, itself, for millions to hundreds of millions of years. So this is something that we've witnessed ourselves happening for a long period of time.

Catastrophic leakage, itself, in a way that will endanger human life or animal life is extremely unlikely. And natural CO2 releases from volcanos -- the Lake Nyos incident is often quoted -- really bear no resemblance to what we're looking at in an engineered reservoir that's specifically designed to retain CO2 for a long period of time.

These were instances that were very different, a volcano or something by definition brings up stuff from the subsurface. A reservoir is something that's designed to do the opposite. And these are not useful analogs for what might happen in CCS. And the IPCC said as much.

Now, there is a bit caveat here, and we can't let industry or anybody else do this of their own accord or will. They need to be adequate regulatory measures that will insure that we pick good sites, that we do adequate monitoring; and that liabilities are properly dealt with to make sure that this is done well.

If this is such a great idea, then why haven't we seen more of it, or why isn't everybody doing it? Barriers, could they be technological? We don't see them as barriers, as such. There remains a lot of work to be done, but we believe that the main barriers here are economic and also policy-related.

We do not try and detract from what needs to be done and learned by doing, or actual research; -- injection, bringing down the costs of capture and so on. But we believe that we know enough to get started.

The main barriers are economic. This does involve additional costs. And at the moment in some country there is no real value or reason to reduce emissions, there are no emission caps, there are no targets and there's no value in reducing these emissions, so why do it. California, of course, is an exception. And we're very glad to see that it's leading the nation in that respect.

Policy. I'll just mention carbon caps. Something that could result in the use of this technology is an emissions performance standard like the one that was voted into Senate Bill 1368. And on this note I would also like to congratulate the Commission for adopting the regulation related to that last week. That's a great development.

Another policy that could lead to the use of CCS is one we call the low carbon generation portfolio standard. This is not something that will be competing with renewables. They should definitely be kept on a separate track.

What you could do there is you mandate a certain percentage of your electricity sales every year, or of your generation, could be met from near-zero emission power plants. And you set the escalating level for that percentage to more or less equal your new coal built.

What we're looking at here is coal plants that will be expensive to retrofit. Retrofit is not a straightforward operation; the -- report said that it's not a linear addition. It requires major overhaul process, redesign, optimization and so on. It becomes much more expensive to retrofit this technology to a plant that's already been built without it, than to build it from day one.

Conventional coal plants for something like 50 or 60 years; they're extremely carbon intensive. If we do build them in the old way then we do run a very clear danger of locking ourselves into emissions for a large number of years. And also to more expensive retrofits.

So we believe that we should set this level of this obligation to equal the rate of new build. Will this be costly? Well, the answer is no if it's spread over a time sectors. And we believe that the impact to the end consumers should be minimal. And we should definitely insure that the impact to disadvantages, sort of energy poor users, should be shielded.

And the reason why this is so small, and we estimated it at about 2 or 3 percent, is because you are not looking at retrofitting your entire coal fleet in one go. You're looking at one plant at a time; spreading this cost over the entire industry sector. It's like a tradeable system.

The other barrier, of course, is regulatory. There is no comprehensive or adequate regulatory framework that will deal with issues related to carbon capture and storage, because no one's had to do it until now.

The EPA has issued some guidance documents on a small scale experimental injections, but really there is nothing at the scale that we need -- and we need it pretty urgently -- that would supply what you have to do to select a site, get it approved; what monitoring requirements would be required; how do you operate the site; who owns the -- space; how do you decommission the site and when are you allowed to do so; who bears the liability for this to make sure that you don't leave an undue burden to consumers and so on.

So, to summarize, we don't believe that coal is clean. Our emissions are growing pretty fast, and our climate is changing even faster. Coal has, and will be responsible for a large portion of these emissions. And really in the amount of time that we have to do something serious about climate is gradually diminishing. And we need to be moving pretty soon.

The longer we wait, the more costly tackling the problem will become. It's going to exacerbate itself, and it's going to become even more expensive. The Stone report pointed that out very clearly.

We need a way to minimize carbon emissions from inevitable coal use; and we need to make sure that this use is inevitable. We need to exhaust all other options well before we look at coal.

And that's where carbon capture and storage comes in. Do we know enough to get started? We believe the answer is yes. There are some technological developments that need to come about, but we think with the right policy and regulations we can get started straightaway.

Dialogue with local communities is essential. We found that out very recently, ourselves, and just because somebody has decided this technology is ready to go doesn't mean that this will be acceptable to everybody. And there are concerns that need to be addressed; and we need to keep our ears open and listen to these people and see what they have to say, because they will be the ones that will be affected by these operations.

And we believe that they can be safe, but we need to spend a good deal of time talking through these issues with them.

Finally, I'd just like to say that there is no time like the present. This is a NASA photograph of the polar ice cap from 1979, and the bottom right is 2003. You can see a marked difference. The projection is that arctic ice could disappear almost completely during the summer months by the latter part of the century.

So, what do we care about the north pole? Well, climate change doesn't make a distinction in geography. And this is a quote by Will Travis of the San Francisco Bay Conservation and Development Commission who said very recently that the problem with climate change is local, and it will have a tremendous impact on San Francisco Bay. And I think there the main focus that will sea level rise, but California is going to be very vulnerable to this problem. And we need to act very soon.

So, thank you very much for your attention. I'll be happy to answer any questions.

PRESIDING MEMBER PFANNENSTIEL: Thank

you very much for a really comprehensive look at this. Questions from the Commissioners?

COMMISSIONER BYRON: May I?

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Byron.

COMMISSIONER BYRON: Dr. Peridas -- do I say it correctly?

DR. PERIDAS: Yes, that's right.

COMMISSIONER BYRON: Very good. Thank you, as well, for coming today. I think your message has been received in California, as you indicated some of the legislation that's been passed. And in no small part as a result of efforts of your organization.

And I sense you don't like coal.

(Laughter.)

DR. PERIDAS: That would be a right perception of the situation, yes.

COMMISSIONER BYRON: So my question would be how come you don't have half as much fervor against natural gas as you do against coal, given that it emits about half as much CO_2 per megawatt hour?

DR. PERIDAS: Well, as I said, the problem here is urgency. If we had 50 years to deal with climate change, then we could be more picky. But given how small the time window to deal with the problem is then we cannot have that luxury.

And I don't know if you've seen the Wedges analysis by the Princeton Environmental Institute, the main message there is that there is no silver bullet, given how soon we need to act.

And to what scale we need to reduce emissions, then we're going to pretty much need every weapon in our arsenal. And this is the so-called Wedge analysis. You know, we need to do everything that we know.

And if it means switching from coal to natural gas, then this is already a significant emission reduction.

COMMISSIONER BYRON: Got you. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much.

MR. SOINSKI: I guess I should question whether on the title of the workshop we should have put clean in parentheses or not. Perhaps be an item for a discussion of the panel, and later this afternoon, also.

My apologies to Dr. Peridas for being out of the room and to the Committee for being out of the room. When you came up I should give you a little bit of background. Obviously people have picked up that you're from NRDC where you are a Fellow on Carbon Capture and Storage.

You currently head the efforts of the NRDC on carbon capture and storage policy and regulation; and you also play an active role in the organization state and federal advocacy efforts.

Prior to joining NRDC in October of 2006, George worked as a senior consultant on energy markets for Poiray (phonetic) in the U.K., is that correct or -- pronunciation?

DR. PERIDAS: It's an unpronounceable Finnish name --

(Laughter.)

MR. SOINSKI: His expertise includes power, oil, natural gas and renewables markets, as well as emissions trading. In that role he worked extensively for the power and oil and gas industries, the finance community and government.

He was part of a team that investigated the economics of carbon capture and storage for the Department of Trade and Industry of the U.K. Government.

He has a masters and PhD degrees in mechanical engineering from the University of Oxford, and a master of science degree in environmental science and policy from Imperial College, London. And he comes from Athens, Georgia. Thank you.

DR. PERIDAS: (inaudible).

MR. SOINSKI: I'm sorry. Why did I say that. My daughter attends Emory University in Atlanta, so to me Athens is the city. My apologies. It actually does say that on his bio.

It's interesting we're going to see the 800-pound gorilla, actually two more 800-pound gorillas later this morning. So that's something you can look forward to in the last session of the day.

The next presentation is on the Carson Hydrogen Power Project. The presenter is Lawrence J. Kostrzewa -- hopefully I did that right -- no, I screwed it up. You know, I'm sorry. You want to tell me what it is?

MR. KOSTRZEWA: Kostrzewa.

MR. SOINSKI: Kostrzewa, oh. I should

know that. Eastern European, I should have no problems with that. Okay.

He has been with Edison Mission Group for eight years, currently as Managing Director of Development. In addition to leading other development efforts, he is responsible for Edison Mission's participations in the carbon hydrogen power project, a 450 megawatt ICGG, which is being developed jointly with bp Alternative Energy.

Prior to his development role, Larry was an Asset Manager for Edison Mission. He has bachelors and masters degrees in mechanical engineering from the Illinois Institute of Technology.

He began his career as an R&D Project Manager for the Gas Research Institute working in the areas of cogeneration, gas engine technology and fuel cells. Areas which I worked before, myself.

From there he joined Indek Energy Services, a privately held independent power producer, as a developer and later a senior vice president for Asset Management.

In his last position prior to Edison Mission Larry was responsible for corporate planning for NTRGY Power Group. He has had a hands-on role in greenfield development and financing of eight successful projects. Larry.

MR. KOSTRZEWA: Thank you. And I'm not an 800-pound gorilla. I'm here to talk about the Carson Hydrogen Power Project. It's a project that really pulls together the things you were just hearing about in terms of integrated gasification combined cycle, as well as carbon capture and storage for a project here in California.

There are a number of things that make us believe that this project has the potential to be applied here in the City of Carson in the L.A. Basin. First of all, we would use petroleum coke, not coal. And we'll get into the differences between those in a second.

Thirteen thousand tons a day of petroleum coke is produced in the L.A. Basin; not imported in, we actually make it here as a byproduct of oil refining.

The plant, itself, would be sited in the Los Angeles load pocket, which is an advantageous place to put power generation. And as in most of California, natural gas is the marginal fuel, so we're really competing with a high cost fuel, as opposed to some of the gasification projects that compete with coal quite a bit of the time.

We have an ample supply of recycled water because of the huge metropolitan area down there. And as the Commission well knows, low greenhouse gas power sources are going to be needed to meet AB-32 and the power procurement portfolio standard and the cap.

In addition we have the potential not just for CO2 storage, but CO2 enhanced oil recovery. And location, which I'll show you in another slide or two, gives us the potential to not just sell electricity, but also produce steam and hydrogen as a result of the gasification process. And, again, in each of those cases natural gas is the alternate fuel. So we're competing against a high-priced product that currently costs quite a bit to develop.

In addition, last year we were selected by the Department of Energy and the IRS to receive a $90 million investment tax credit under the Energy Policy Act. That's all the good news.

There's some unique challenges doing it here. One is that best available control technology for air emissions in the L.A. Basin is emissions no worse than a natural gas combined cycle. That's cleaner than any IGCC has ever been asked to achieve before, and it's a technical and cost hurdle.

Secondly, it's in an urban industrial setting, not out in the middle of nowhere. And so we have neighbors that we don't want to upset. In addition, as with any carbon capture and storage project, we're confronting, in real time, the unclear legal and regulatory framework for CO2 storage, and the long-term liability aspects that come with that.

Just a quick foray into what petroleum coke. Petroleum coke, which I guess you have a sample for there, Stu had show-and-tell; that's fun. It's an unavoidable solid byproduct that you get when you make oil. You extract all the useful liquid products and gaseous products out of crude oil, and what you get left is that. It still contains an awful lot of energy.

And it ends up being quite a bit different from coal. Here's a chart comparing Powder River Basin coal with petroleum coke. Petroleum coke has a lot less moisture, a lot less volatile matter, but quite a bit more sulfur, and quite a bit less ash. So it's a different animal.

And really only integrated gasification combined cycle allow the level of sulfur removal that we would need to meet the strict local emissions. Of course, this pet coke is currently shipped to markets in Asia where those stringent emission control requirements don't apply.

This is kind of neat aerial of the area. In the foreground is the City of Carson; and in the background is the Port of Long Beach. Outlined in red there is where the Carson Hydrogen Power Project would be located. Outlined in yellow is bp's Carson Refinery, Edison Mission Energy and bp Alternative Energy, our partners in this project.

The two little boxes outlined in blue are electrical substations, so you can see we're quite well located to hook up to the grid. And outlined in the kind of the bright green there is a hydrogen production facility, currently -- products through steam methane reforming, converts natural gas into hydrogen for refinery use. And so we have a hydrogen market and a hydrogen network right next door.

In addition, you can see the other refineries in the area, Conoco-Phillips, Tesoro, Volero and another Conoco-Phillips refinery off to the side. And these are all producing the petroleum coke. It is all trucked to Long Beach Harbor where it is shipped overseas.

And essentially all that pet coke goes past our site. And so one of the advantages that we have is that truck traffic would be eliminated.

This is a cartoon, not really a technical drawing, of what the process looks like. I won't go into too much detail, but we start out with our fuel, petroleum coke which we receive from the local refineries.

The second step is to gasify it. Then the next step is to, well, there's actually an intermediate step where we shift the combustion products. As Stu said, the gasifiers make carbon monoxide and a little bit of hydrogen. We want lots of hydrogen, and so we convert then, in a second step, the carbon monoxide into carbon dioxide and hydrogen.

Then we separate out both the sulfur products and the carbon dioxide. The carbon dioxide is compressed and pumped underground. The hydrogen is then sent to a conventional combined cycle power plant, or largely conventional. There's a few technology tweaks to be able to burn hydrogen in the gas turbine, but other than that it's the same.

There are a number of considerations we've had to deal with, primarily on the environmental side, to make this project work. On the air quality side, I talked about truck transportation, but also the ships in and out of Long Beach Harbor, eliminating 5000 tons a day of ship transport reduces emissions, as well.

We did find it necessary to apply the more expensive Rectisol AGR, acid gas removal; after the synthesis gas you have to separate out the sulfur. And there's a number of technologies for that. Rectisol is the most expensive, but gets you down to actually sulfur levels at or below what exists in natural gas.

We needed to do that in order to meet the sulfur limits, but also to minimize particulate matter production. Again, to get down to the same as natural gas. We also will be filtering the synthesis gas in order to capture any remaining particulates.

They hydrogen sulfide gas is pulled out, and the gas removal goes to a sulfur recovery unit where we make elemental sulfur. That process has a tail gas that we recycle back into the process, so that there's actually no direct pipe-to-atmosphere from the gas treatment process.

And then any nonemergency process vent, that's all collected and brought into emission control.

We use recycled water for all of our plant requirements. On the process wastewater we'll have zero liquid discharge. And Fluxant, that's another word you probably haven't heard. Because petroleum coke is so low in ash, you actually have to put a little ground-up rock in there to capture the ash that is in there.

And it does currently look like we'll be able to use that resulting slag for metals recovery, which is pretty neat.

And lastly, of course, a big goal of the project is to capture what we are going to capture and we are going to either store or sell the carbon dioxide that results up to about 90 percent of the carbon that was in the fuel in the first place. And it will either be stored in a depleted oil and gas field, a saline aquifer, or possibly for enhanced oil recovery.

This is a comparison of greenhouse gas emissions from various technologies. It kind of follows on with the stuff the Stu was showing. The green bar there is California, 1100 pounds per megawatt hour standard. I seem to have lost the label off the left side. Well, I guess it's on the top, pounds per megawatt hour.

And you can't quite see it, but all the way on the right there, that's the Carson Hydrogen Power Project, which is below any of the coal options and below the gas options, as well.

This is just a quick brief on the CO_2 storage aspect of the project. DOE issued a report that showed that there's over a billion tons of CO_2 storage capacity in the local oil fields around us. That excludes saline aquifers, which are immensely larger than that.

If enhanced oil recovery is possible, there's 57 billion barrels of stranded oil in California that won't come out without a tertiary recovery process. About 5 to 10 percent of that can be recoverable with enhanced oil recovery.

We have studies underway to determine

the most suitable, safest, most economical place to put the CO_2, whether that's storage or enhanced oil recovery. And the studies would include devaluating recovery potential in the case of enhanced oil recovery; characterizing reservoirs for the safe, long-term capture and sequestration of the CO_2; pipeline routes to get there; and the monitoring techniques that will be necessary to gain the assurance that the CO_2 is where we put it and stays where we want it to stay.

I won't talk about this too much, Stu covered this already. There's lots of numbers out there as to what these things will cost. Stu mentioned the Duke Edwards Port project at about $2 billion; the Mesaba project at $2.3 billion. And as he said, those aren't on the same basis, you can't really compare them. FutureGen will talk about -- after me, so I won't talk about that.

And then our project, which is an IGCC using pet coke with carbon capture and storage and polygeneration. So technologically not really comparable to the others. We think that will cost on the order of $2 billion. We have an updated cost estimate coming later this year.

You've seen these. The chart on the left, I think you remember that colorful chart that Stu had showing how optimism became reality, became cost reduction. The chart on the left is real data for flue gas to sulfurization illustrating that chart.

At the study stage it looks very cost effective; then you get to the early units, and wow, it costs more than you thought. And then technology advancement brings it down in time. And in this particular circumstance you also saw his chart on the right, which is that technology cost curve is running headlong into what's happening with global construction costs and commodity cost escalation.

And here is Stu's chart. And what I've done is just circled the three pieces of technology that make up the Carson Hydrogen Power Project. IGCC, carbon capture and -- I'm sorry, CO2 capture, and CO2 storage. And really just making the point here that as an initial commercial demonstration, we're at the high side of that curve and public policy support is going to be necessary to move past that high hump on the technology learning curve.

I think that's all I have. Well, I guess just to talk about who is involved here. bp and Edison Mission are the owners of the project. We're being supported by GE Energy as the technology provider, both of the gasification equipment and the turbines. We're working with Fluor as our engineer, an EPC contractor. And West Basin Water District is our water supplier.

And with that I'll take any questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions?

ASSOCIATE MEMBER GEESMAN: You mentioned you intend to use proven gasification technology. And I was wondering if you were expecting to require the same degree of redundancy in the gasifiers that the Tampa IGCC has found necessary.

MR. KOSTRZEWA: Well, the redundancy is really an economic choice. And what we have found is that a spare gasifier is going to be cost-justified in this project. So, under normal operation we'll have three gasifiers running, and we'll have a fourth spare. We'll have two gas treatment streams, we won't have redundancy in the gas treatment stream. If one of those goes down, we would operate at half load, or half gasifier load. But those are more reliable than the gasifiers, themselves.

ASSOCIATE MEMBER GEESMAN: What do you expect to do with the electricity generated from the project?

MR. KOSTRZEWA: We hope to get a long-term power contract to sell it. And that's kind of the commercial hinge-pin that makes it all work. At the kind of capital costs that you're talking about there, we won't be able to sell power for market price. And so, you know, we'll put this out there as an option to the state. We don't really know how to bridge that gap at the moment.

ASSOCIATE MEMBER GEESMAN: There's obviously a lot of talk about the potential scale-up of a new phase of the WESTCARB carbon capture and sequestration efforts. I take it that this project potentially could be one of the leading candidates for that.

MR. KOSTRZEWA: We're working with WESTCARB in two different ways. One is an earlier, smaller scale demonstration in the area. And then we would hope to dovetail that with the full IGCC in the longer term.

ASSOCIATE MEMBER GEESMAN: You also mentioned the uncertain regulatory environment. I wonder if you've given any thought to, assuming that you do proceed with significant WESTCARB support, how you would address, or how the Energy Commission should address any structural conflicts of interest that could impair the Energy Commission's ability to render a disinterested licensing decision for the project.

MR. KOSTRZEWA: No, I haven't actually thought about that, but I recognize that that's a possibility. The licensing of the CO2 storage facility, itself, would be done by EPA. And so that does provide a disinterested third party. And, you know, with regard to the actual CO2 storage, it's not a really commercial business for either the CEC or for us at the demonstration scale. And so, I think, again, thinking off the top of my head, it's a pretty clean story.

ASSOCIATE MEMBER GEESMAN: I'd invite you to take the opportunity to give some additional thought to that. I suspect that's likely to be one of the critical regulatory-related issues that the Commission has to address in this year's IEPR cycle. And certainly you and any other interested parties could greatly help us in trying to sort through our options if you'd share your written thoughts with us.

MR. KOSTRZEWA: That's some excellent feedback. We'll put that -- take that to heart.

COMMISSIONER BOYD: I'm wondering if you could tell us how much of the regionally locally produced petroleum coke would this facility utilize.

MR. KOSTRZEWA: We plan to gasify about 5000 tons a day out of the 13,000 tons or so that are available, that pass through Long Beach Harbor.

COMMISSIONER BOYD: Is there any way of moving your coke supply to your facility, move the technology, other than by truck?

MR. KOSTRZEWA: As you saw from the aerial view, there are two refineries. Maybe I can go back there. Two other adjoining refineries. Quite conveniently bp's current coke storage is right here. Conoco-Phillips is right here. And Shell is right there -- or Tesoro now is right there.

And so certainly the bp coke will be conveyed to the site. Conoco-Phillips, if we end up making a commercial arrangement with Conoco-Phillips, could be conveyed to the site. And, you know, physically there's no reason we couldn't move the Shell coke, as well.

The more distant refineries would have to be trucked.

COMMISSIONER BOYD: And lastly, the power that you do -- the electricity that you do produce from this facility, do you intend to use some of it for the refineries load?

MR. KOSTRZEWA: No. The bp refinery currently has a cogeneration plant, also jointly owned by bp/Edison Mission, that supplies its local load. Sales across the public way to the adjoining refineries has a lot of regulatory barriers to that.

COMMISSIONER BOYD: Thank you.

COMMISSIONER BYRON: Mr. Kostrzewa, if I may, --

MR. KOSTRZEWA: Sorry.

COMMISSIONER BYRON: -- if I've done my math correctly, and please correct me if I'm wrong, about $2 billion project, 450 megawatts puts you right in line, if I go back to Mr. Dalton's presentation, at about $4400 or $4500 a kilowatt. And then if I go over to cost of energy and make that comparison, it looks like it's going to be about 11 cents a kilowatt hour on a 30-year life. That's pretty expensive power.

And, of course, it's doing a lot of good things, including taking a great deal of coke out of the third world market that would be burned, otherwise. But at 11 cents, if I'm in the ballpark, it's not going to compete very well. Do you need some sort of incentives or something to make this work?

MR. KOSTRZEWA: Your math is very good. And it is more expensive to build a plant of this sort in California than the plants -- I think EPRI's basis is Kenosha, Wisconsin. Just meeting all those environmental restrictions that we have here that would not apply there, increase the cost of the plant; plus the higher cost of L.A. labor does drives the cost up.

And, yes, 11 cents is well above the CPUC's market price referent for what new power costs. It could be smaller if we're able to get revenue for CO2 sales. It is somewhat reduced by hydrogen and steam sales, but it's still going to be well above market.

And really what we're finding is that this will be a technology and policy option that we'll make available. But somebody's going to need to span that gap.

COMMISSIONER BYRON: Forgive me if I'm pressing the question. Have you thought about how you're going to span that gap?

MR. KOSTRZEWA: We plan to talk to the California Public Utilities Commission and any other agencies that are interested in our story. And, you know, basically here's what it costs if we want to develop the technology option. It is first of a kind, it's going to cost more. We can't afford to do it without some help.

COMMISSIONER BYRON: Well, we're certainly in favor of this technology, so I guess I would ask the same sort of thing Commissioner Geesman's indicated, and that is please stay in touch with us and let us know in writing what kind of issues we need to address here at the Energy Commission to help promote this technology.

MR. KOSTRZEWA: We will. You know, as the NRDC representative indicated, without a price for carbon or a price for CO2, you know, 20 years from now that will fill the missing money. But we need something more now. And I'll take advantage of that opportunity.

COMMISSIONER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Are you -- you said that the CO_2 would either be sold or stored. Are you looking at -- what value are you looking at for the sales of that CO_2?

MR. KOSTRZEWA: I should clarify. It will either be sold and stored, or stored. We would not sell it without the requirement that once the CO_2 is used for recovery --

PRESIDING MEMBER PFANNENSTIEL: I understood -- no, I understood that --

MR. KOSTRZEWA: -- that it would --

PRESIDING MEMBER PFANNENSTIEL: -- and I assumed that it would be like for enhanced oil recovery kind of use. And so I assumed there'd be a value. And have you imputed any value or how are you thinking about that?

MR. KOSTRZEWA: Well, we are in discussions with companies that would like to use the CO_2 for enhanced oil recovery. But it's in a commercial stage where we can't really talk about prices.

We know what carbon dioxide is sold for

in the Permian Basin of Texas. We have a sense for what CO2 is worth in terms of additional oil that's produced. And we know what it costs us.

And so we think we kind of have the bounds on that equation. But, also have to have a willing customer that sees things the same way. And we're in those discussions now.

PRESIDING MEMBER PFANNENSTIEL: Are you assuming that the entire output, the CO2, could be sold?

MR. KOSTRZEWA: We will produce on the order of 5 million tons a year. And indications are that there are a number of oilfields in California that are capable of using that kind of quantity.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions? Thanks very much.

MR. SOINSKI: We have 15 people who are viewing this presentation via Webex. One of them is Michael Mudd, who's our next speaker. And before I go on to read you Michael Mudd's r,sum and get him online, I'd like to mention that there are copies of the morning presentations on the table if you'd like to pick up one, or multiple copies.

So, are you going to un-mute him?

MR. MUDD: Good morning; can you hear me?

MR. SOINSKI: Mr. Mudd. Wonderful, we can hear you.

MR. MUDD: Good.

MR. SOINSKI: Do you have a full-screen display of your presentation in front of you?

MR. MUDD: Yes, I do. I'm all set. So, (indiscernible) for me.

MR. SOINSKI: Okay, does that work? Oh, you have presenter right, so you should be able to click through it, yourself. You want to try to do that?

MR. MUDD: I don't -- do that.

MR. SOINSKI: Okay, you can use your arrows on your keyboard, the left and right, is that correct?

MR. MUDD: No. (indiscernible) be as easy.

MR. SOINSKI: Let me just check with -- okay, we'll do that. Thank you. I appreciate your doing this. This is the first time I've tried to do this at a workshop, so. Okay, while we're resolving technical difficulties, I will read your biography.

Prior to -- well, first of all, Michael Mudd is the Chief Executive Officer of the FutureGen Alliance, Incorporated. Prior to being named CEO of the FutureGen Alliance, Mike spent his professional career with American Electric Power, Incorporated, mostly focused on coal-fired generation.

During his more than 30 years with AEP, he was involved in the design, construction, start up, and operation of large coal-fired power plants including AEP's 1300 megawatt and 600 megawatt coal-fired power plants. He was responsible for several clean coal technology demonstration projects including the Project Manager for the 70 megawatt TID pressurized fluidized bed combustion demonstration plant.

After taking an assignment as a developer in the nonregulated utility business responsible for the development of cogeneration projects in the U.S. and Canada, and IPP projects in Mexico, Mr. Mudd returned to the R&D arena with AEP where he was responsible for corporate R&D associated with energy supply technologies, including coal, gas, nuclear and renewable energy technology as the Manager of Technology Development.

Mike played a key role in the analysis that led to AEP's decision to proceed with developing its IGCC projects.

In September of 2006 Mike was named the Chief Executive Officer for the FutureGen Alliance, a nonprofit corporation comprising America's largest electric utilities and coal companies that will partner with the USDOE to design, construct and operate the world's first near zero emissions coal-fired power plant.

He's active in several industry associations including participation in committees associated with the Coal Utilization Research Council, the Electric Power Research Institute, the IEA Coal Industry Advisory Board, the National Coal Council, the National Academy and the DOE Hydrogen Technology Advisory Committee.

Mike has a bachelor of engineering degree and with post-graduate studies from Stevens Institute of Technology, as well as the AEP's Strategic Leadership Program at the Fisher College of Business at the Ohio State University.

Mr. Mudd, I think we're ready for your

presentation.

MR. MUDD: Thank you, and good morning. Would you please go to the first slide. And once again, it's an honor for me to have the chance to speak with you. If you click once to bring on the words there.

These first couple of slides put in context, they're not far different from the presentation that you heard from Dr. Peridas from NRDC. That there is overwhelming evidence the scale of the global energy system, it is immense and growing.

We need energy conservation. I hope people recognize it's impossible to conserve our way to the complete solution. Fossil fuels, they are affordable and abundant and they will be used. Advanced technology is required to reduce the cost of managing CO2 -- and anyone who looks at that single solution, I think, will, at the end of the day, be frustrated, because there's no one silver bullet. We need all options. And those options are needed at a big scale.

How can we get there? Through R&D, reduce the cost and improve the performance. You heard that from Stu Dalton. I think we all agree the next ten years is a critical window in which to prove the advanced technology.

Next slide, please. And carbon capture and sequestration are recognized as a key part of the solution if we raise the fact that we do need fossil fuels. A lot of these, of course, you already heard about.

But we have to recognize that they need to be proven. And they have to be proven at a commercial scale, at multiple places around the globe, and now.

Next slide, please. A question came up about natural gas, and I'd like to give my context. In fact, one of the drivers why I am so keyed on the importance of coal and FutureGen. We've heard our President speak about how we, as a nation, are addicted to imported oil. At the same time as we say the possibility of having natural gas replace more and more coal plants.

Many of you perhaps have heard about just a couple months ago there was a meeting. And the meeting was among the countries that now produce most of the natural gas that plan on getting into liquified natural gas business. Qatar, Iran, Venezuela, Libya, Indonesia, members of OPEC.

And they're looking at forming the same type of cartel as OPEC to basically allocate market shares and quote-unquote defend the price of gas.

I don't want my children's president to hear them talking about their addiction to imported natural gas, and that cartel determining how much they'll pay for electricity and when they turn their lights on and off.

But now let's move to FutureGen. I hope I've given the message, it is the right technology at the right time. FutureGen will be the world's first near zero emission coal-fired plant. It will capture and inject 1 million tons of CO_2 per year. It'll be a living laboratory, as you'll see in a bit. It's not just build, status quo, state of the art IGCC technology, but advance the technology. As you'll see it's a global public/private partnership with involvement of many stakeholders.

Next slide, please. It also has very clear and important objectives. To design and build and operate the first near zero emission coal-fired plant. As I said, to capture more than

1 million tons per year in a deep saline geologic formation. Not through enhanced oil recovery, not a way to make revenue, but to inject it in geological formations. The near zero level of NOx, SOx, particulate matter and mercury. To be online by 2012. And to advance the technology.

Right now you saw that chart that Stu Dalton had showed, the first couple plants will be more effective. We have to move beyond those first plants in order to reduce the cost. An important part of FutureGen is to find a way to reduce those costs, that future plants can be lower cost and yield lower cost power to our customers. And also to build stakeholder acceptance.

Next slide, please. Why we need FutureGen. It's the unique opportunity to prove carbon injection in deep geological formation. That's different from enhanced oil recovery. Many of the projects they're looking at are focusing on EOR. EOR is very important; it's critical to the petrochemical industry; it's a fantastic opportunity for our company to extract more domestic oil from older oil wells.

But if you look at most of the power

plants in our country and where the coal is and those plants are, there's not the opportunity for enhanced oil recovery. Most of the CO will not have economic value. Most of it will need to be injected in deep saline geographical formations.

Therefore, it must be proven. And that's not trivial, because there's legal and regulatory framework that must be developed. That framework, in general, does not exist right now. And we need projects like FutureGen to form that in the right way.

It has the opportunity to advance IGCC technology; it's not driven by business considerations that lead to risk averse (inaudible). We heard the talk about the DP Carson project. At the end of the day they need contracts for the sale of electricity, for the sale of the CO2, the sale of steam and chemicals to the refineries, which is good. That's a fantastic project.

But if you're a developer having to develop a project with those type of contracts, it's not conducive to taking the risks that a project like FutureGen can take in order to further advance the technology as we try to push

IGCC towards efficiency and low emissions that it truly has the opportunity to do.

There are also no IGCC projects with carbon capture and sequestration as far developed as FutureGen. Because of the R&D nature, we don't need to have those business contracts. We don't need cost recovery as with other projects -- on track to be online in 2012. The only constraint is funding from the U.S. Government, which, in general, is in good shape.

And furthermore, you have international participation (inaudible). We've heard talk about regardless of what the U.S. does, evolving economies will grow, build more power plants, burn more coal. So involvement by companies in other countries will insure that those other countries need the opportunity and the pros and cons of technology with carbon capture and sequestration.

Next slide, please. So these are the right markers for FutureGen. In 12 of the leading companies with operations on six continents throughout the world, I won't go through the list, I hope that you recognize many of them.

There was a question that was asked before by Stu Dalton, says is industry investing in R&D for carbon capture and sequestration. You're looking here at 12 companies that are investing selectively between them $400 million.

FutureGen is a 501(c)(3) not-for-profit entity. Therefore the companies investing in FutureGen cannot get any return on investment. In fact, it's not an investment; it is a contribution. They cannot get any ID rights. So, here 12 companies are contributing towards R&D in order to advance this important technology.

On the government side there's involvement by the U.S. Government, China, India, South Korea and Japan. They're meeting with several other governments. With partners, technical support from Battelle, a worldwide R&D organization. We've also engaged many world class technical experts in the project, including many from EPRI. And we're getting engineering support from world class EGC firms.

Therefore, it's well positioned to build worldwide acceptance involving the right stakeholders, the right coal companies and the right utilities.

Next slide, please. Now, I mentioned this, so I'll just once again bring it forth. You saw the one, I'll say the cartoons from bp. I'm sure Stu has, and will show, slides for IGCC technology.

But FutureGen, because of its R&D nature, Stu said how when you look at the lower ranked coals how these plants tend to have an advantage. There's a distinct penalty when you burn low-ranked coals with IGCC. That is a penalty that needs to and should be addressed if we embrace the fact that IGCC does have the opportunity to burn coal more and more cleanly.

We can take those features and -- features in IGCC to burn both western and eastern coal; advance gasification, hydrogen turbine. A hydrogen turbine is not trivial. You've heard some of the vendors, perhaps, say no problem, they've done it. They've done it with tiny turbines, the 10, 20 megawatt turbines. Not the large F class turbines that we have for these type of IGCC plants.

You've heard us talking about blending hydrogen. Well, perhaps 30, 40, maybe 50 percent hydrogen. Maybe high concentrations for a couple hours. That's not what you need. When you have the type of investments we're talking about the billion-dollar investment, that hydrogen turbine had better run. If it doesn't the IGCC won't run, regardless of how much redundancy you have in the gasifiers. Therefore it's a critical development item that FutureGen can address the way that no other project can.

The integration of carbon capture and IGCC is also not trivial. Many times you'll see presentations that talk about, you know, gasifiers here, gasifiers there, and so on. When you take a gasifier and integrate it with a gas turbine for IGCC technology, you've increased the level of the steam complex by quite a bit.

Now you add carbon capture and sequestration, including the continuous injection of CO2, that's another level of complexity that must be understood and addressed. And it's not trivial. But projects like FutureGen, we can handle that.

And also addresses the operation of the plant. For example, if you're operating the plant and injecting CO2 into the well, what if the compressor that injects CO2 into that well trips. Do you have to trip the whole plant? Can you leave the CO2 in the pipeline? You need to do things like that, very complex issues that must be addressed. FutureGen can take care of those issues.

The next slide, please. Again, a carbon sequestration technology. Futuregen will be world class, first of a kind, MMV system, measuring, monitoring and verification system.

The story I like to tell is that when you -- if you were a utility executive wanting to build a power plant with carbon capture and sequestration and you're at a public hearing, and people say, can you tell me exactly how that CO2 will behave in a deep saline formation.

The only answer that one can give is, well, we've got the best PhDs in the world, many from California, who are running some of the best computer models that have ever been written on super powerful computers, and this is a model they've done. And then you put up on the presentation this plume which grows after a couple years and then stops. And then, see, there's no problem.

Would that give you the comfort level if you were at a public hearing to be able to say, I trust that guy, I trust those models, and no problem. I believe the CO_2 will behave. How can we get the widespread deployment of injection of CO_2 in deep geological formations at this level.

But if we take a project like FutureGen, and now we say we've done that -- first of all, we've done much more higher level of characterization of the geology. We've done that model. We have a very sophisticated measuring, monitoring and verification system. And now we've done it; we've measured it; we've tested it. And now we understand it and we've calibrated that model.

You would certainly hope that that will lead to a much higher level of confidence of carbon injection as we go forward and want to have these type of plants built throughout the whole country. In fact, the whole world.

I also cue you to that box on the bottom left; 11 gigatons of potentially available CO_2 capacity throughout the world. That is in deep geological saline formation, so it shows how robust that is.

Next slide, please. Talk a little bit about the site selection process. Last year about this time the Alliance went out for request for bid to say who would like to have FutureGen built in their area. And also we've heard of NIMBYs; I think FutureGen has shown what I'll say is BIMBY, build in my backyard, because we put out that RFP and we got bids from 12 sites in seven states.

Each one of these areas said we want you to build a research project in our area. We understand the importance of coal; understand the economic benefit of building a plant like FutureGen.

We went through a very detailed analysis. And after that we came up where they showed us the four sites in two states, two in Texas and two in Illinois. And we've been going through the NEPA process to do the environmental impact statement.

Next slide, please. And these are the four sites here; shows the pictures of them. We expect to select the final site in September.

Next slide, please. Anyway, the Department of Energy has just issued its draft environmental impact statement, a 1200-page volume to look at all the environmental impacts. Hearings will be held next month. And then we accept, like I said, the final site.

We've gone through a conceptual design, the plans will have multiple choices of how the power plant should be done. Make sure it's fuel flexible. We come up with cost estimates, the engineering manager on board. And we expect to purchase the major equipment very soon.

Next slide, please. This is the one I was looking for. The environmental impact statement. They concluded no significant adverse impacts. This is the first time that we've gone through an environmental impact statement, not only for a power plant, but also for injection site. And what's interesting, also for the pipeline.

In the past the CO2 pipelines were just built based on the common -- that exist. But as part of this project they actually did an EIS analysis on the pipeline. The public hearings and comments will be coming up in about three or four weeks this June.

Next slide, please. The project cost. As you see, we started out as a $1 billion project, but everyone has shared the pain of increased power plant costs. Right now the cost is, based on the same scope as we started out with, $1.5 (inaudible) dollars, with 74 percent coming from the U.S. Government -- I'm sorry, that's 74 percent, 26 percent coming from the Alliance.

Click one, please. This shows the schedule coming up next. The schedule shows that we would expect to be breaking ground in 2009; the start-up of the plant in 2012.

Next slide, please. The current activities are we are finalizing the contract with the engineering construction management to continue with the current specifications. With that we will take off on our preliminary design. Done extensive technology and due diligence, focusing more on what should future power plants look like (inaudible) carbon capture and sequestration.

And then how can FutureGen get us there to reduce the costs and improve the performance of future plants, with the technology specifications, going through due diligence on the site, leading to final -- site in a month or so. And as I mentioned, the public hearings are going on and the environmental impact statement.

Next slide, please. So, in conclusion

FutureGen supports a technology-based climate change strategy. One needs technology to support any policy that comes up for climate change. FutureGen gives us that opportunity because it validates the cost and the performance of an integrated zero emission plan. And the technical basis to retain coal in the U.S. and global energy mix, but zero emissions of power plants. And doing this the way it should, the cost -- with both the U.S. Government, with industry and other stakeholders.

That ends my talk, and I'm welcome to hear any questions anyone might have.

PRESIDING MEMBER PFANNENSTIEL: Questions, Commissioners? Commissioner Byron.

COMMISSIONER BYRON: Mr. Mudd, this is Commissioner Byron. Thank you very much for your presentation.

MR. MUDD: You're welcome.

COMMISSIONER BYRON: I didn't see the size of the plant. Would you mind giving me the megawatts?

MR. MUDD: It's 275 megawatts. Basically most of the commercial IGCC plants are using what's called an F class turbine, which is about 185 megawatts, coupled with the steam turbine gives it 275 megawatts.

So this is representative of the module of a typical IGCC plant.

COMMISSIONER BYRON: Fantastic. Looks like a very good project. I don't have any other questions right now, but thanks, again, for your presentation.

MR. MUDD: You're welcome.

PRESIDING MEMBER PFANNENSTIEL: Mr. Mudd, you mentioned several other governments besides the United States, that were partners, India, China, South Korea and Japan. Are they contributing financially?

MR. MUDD: Yes, they are. With the Alliance, itself, the U.S. Government is contributing 74 percent of the cost. And the U.S. Government has set a standard asking for other governments to contribute $10 million each. Not a lot of money. But nevertheless, to get their involvement.

And for that $10 million each they get to sit on the international steering group, which can get upfront, early information on the project.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Very good. Other questions. Thank you very much.

MR. MUDD: You're welcome; have a good day.

MR. SOINSKI: Mr. Mudd, will you be able to be available for the panel discussions, or do you need to go off to other things?

MR. MUDD: I'll be available for the one this morning.

MR. SOINSKI: Okay, very good. Thank you.

MR. MUDD: Right.

MR. SOINSKI: Our next presentation is on western coal: combustion, gasification, electricity generation and carbon sequestration. A view from the State of Montana.

And the presenter is Tom Kaiserski, who is a Senior Economic Development Specialist with Montana Governor Bryan Schweitzer's Office of Economic Development.

He has been concentrating on energy development while working for Governor Schweitzer, which has included efforts on clean coal and transmission line projects.

He has traveled around the region

presenting information on the Governor's energy policy which promotes developing all of Montana's energy opportunities. This includes emphasis on developing wind, biofuels, coal, oil and gas energy sources that eastern Montana has in abundant supply; and which the Governor believes is one of the keys to national energy independence and revitalizing the economy of eastern Montana.

Tom grew up in Los Angeles; has a bachelors degree in earth science from Montana State University in Bozeman. And prior to coming on board with the Governor's Office in January 2005, he worked for seven years at the Economic Development Coordinator for the Beartooth RC&D, a regional economic and community development organization that serve the five-county region around Billings, Montana.

Tom has worked as a community planner in Montana for more than 15 years.

MR. KAISERSKI: Thank you very much, Commissioners, for having me. Art mentioned I'm from Los Angeles originally. I moved to Montana about 30 years ago. But it's my first trip to Sacramento. I have all my family still in Los Angeles, so it's quite thrilling for me to be able to come and interact with the State of California and see the ways that the State of Montana can try and address some of the issues that are facing the State of California, and indeed, the nation.

And so I'm here to talk about Governor Brian Schweitzer's vision for energy development here. I know it's in the context of a discussion about clean coal and carbon sequestration. And consider this presentation really about Governor Schweitzer's overall view of energy development. Coal plays a big part of that, but so do renewables, as well.

And so bear with me in this discussion; we do talk about things other than coal, but we think it's important because it really offers the perspective of what a state that's rich in energy resources in the United States, that's very low density population where the - just behind California in terms of land area, but we've only got 940,000 people in the state, so it's very low population. And folks are very interested in energy development in the State of Montana, as is the Governor.

So, I started this presentation about Montana energy to just talk about our economy.

And generally the economy in Montana is fairly strong in many respects.

(Pause.)

MR. KAISERSKI: Okay, hopefully we're underway. Montana, as I mentioned, is a rural state, but it has a fast growing economy; the seventh fastest growing in the last three years. Although that's very spotty, and we'll talk about that.

Our unemployment rates are very low, the lowest in the nation right now, 2 percent. And sometimes that can be misleading because the eastern part of the state, the prairie part of the state, though unemployment is low there, but that's a fairly economically distressed area. And the reason the unemployment is low there is because when people don't have a job they move. And so there aren't a lot of unemployed people around. And that's part of that spottiness I talked about.

But nonetheless, our economy is fairly strong in Montana with a record number of jobs in 2005.

In Montana we talk about, in the economic development field -- and I'm an economic developer. And that's a big part of what Governor Schweitzer sees energy development as being important to Montana. It's a great economic development tool.

And so we look at the comparative advantages that a place has in the economic development field. What are the inherent things that make an area attractive. Well, Montana has minerals, forest products, agricultural products and also energy. And from those we have the opportunity to develop all kinds of energy resources.

In minerals we have the only platinum and palladium mine in the western hemisphere is located near Billings, Montana. And platinum and palladium is the key technology involved with fuel cells.

Forest products, we have a lot of opportunity for biomass energy. The western part of the state has a lot of forested area.

And then from agriculture we have the opportunity for biofuels development; that being ethanol or biodiesel.

And then for energy resources strictly, we have huge coal reserves, and we're going to talk about that. We can mine the coal or turn it into gas, as we've talked about; make liquid fuels out of it; or turn it into electricity.

Montana has huge wind resources and we're going to show you what those wind resources are, which is, of course, a clean, renewable energy source that's greenhouse gas free. And we can develop windfarms in the State of Montana, especially in that eastern part of the state that's very low populated.

And then we own gas, and Montana's a fairly significant producer of oil and gas. And, in fact, is one of only two states whose production of oil has increased recently. It's actually doubled since 2007, up to about 33 million barrels a year.

So, energy is very important to Governor Schweitzer. I know he's gone around the country really promoting energy development, as something that's important to the nation and something very important to the State of Montana, in terms of economic development. So the red box indicates all the things that I'm going to talk to you about today in terms of energy development.

So, Governor Schweitzer really provides

vigorous leadership for the State of Montana. He's not a career politician. This is his first elected position here as Governor of Montana; elected in 2004. He's a scientist, and an international agribusinessman. He got a degree from Montana State and worked overseas in Saudi Arabia. He speaks Arabic. Worked there for seven years developing irrigation projects. So he really understands the technical side of this whole energy question.

He's very very positive. Has a great can-do attitude. He doesn't say -- it's very much what are the possibilities, how can we get things done. He's very intelligent and creative and will work with anyone. And he's shown that in his two years.

He's a real visionary leader. And what is that vision, then, that the Governor has for Montana. We'd like to strengthen and diversify our economy. Because I mentioned while it's growing, it's very spotty. We've got parts of the state that really need it.

So he wants to develop these various sectors of our economy, the resource sector, manufacturing sector and on. And he'd like to increase the number of jobs in the state. While we have a lot of jobs, I mentioned earlier 483,000 jobs in the state, a lot of them are kind of lower paying jobs. And so we need energy development because it creates higher paying jobs. And that's what he's really trying to do.

And he'd like to geographically disperse the jobs in the State of Montana. And this is an important thing to remember. And these are important slides to talk about.

Kind of a cute graphic here. The Governor describes Montana's economy as a cowboy boot. And the reason he does that is because those high growth rates that I mentioned really are occurring in that boot-shaped area that are the nine counties of western -- located kind of along the Continental Divide in western Montana. That's where the job growth is occurring and the economy really is booming. And it really is kind of an island of prosperity.

But the Governor really sees outside that boot as where the real potential lies for economic development. And he sees that being an energy development. So that area outside the boot, eastern Montana, is where the opportunity really exists.

And eastern Montana, as I said, it's sparsely populated; it's a prairie part of the country; it's semi-arid; it's grassland. And it's an area where the populace is very very interested in energy development, and very very in favor of it.

What's the Governor's policy for outside-the-boot energy development? Well, first of all, he'd like to take advantage of all those energy advantages that are out there. And that's principally what I'm going to talk about today.

He wants to do it right. And we've heard a lot today about the environmental aspects, or the issues involving coal use. And so doing it right means carbon capture and sequestration. It means using advanced coal technologies when we're talking about coal development. Because we want to preserve the way of life that Montana has. A lot of us live in Montana because of the kind of the rural pristine-ness of it. And so that means doing things clean and green.

So, in Montana, when we look at the energy policy that the Governor's really putting forth for the state, it has implications, though, on an international level principally because the Governor, while he advocates for coal development, is very very strongly in favor of carbon capture and sequestration. In fact, he publicly stated it in his State of the State Message in January, that all new coal plants should capture and sequester their carbon dioxide.

And so from an international level our energy policies are important because we've got to address this issue of climate change. And the Governor is fully engaged with that issue.

From a national level, energy independence is very important. The Governor views Montana as a state that can be an important player in providing energy supply for the United States from domestic sources. And so we're going to talk about that today.

From the state's point of view economic development is very important. As I mentioned, that outside-the-boot area has been an area of economic distress for decades. Many of those areas, much of eastern Montana still hasn't attained the population that it had maybe back in the 1920s. They're still probably 30 percent below the population figures of 60, 70 years ago.

And so that area is really really hungry for economic development.

He believes that Montana can help solve America's energy independence challenge. And he looks at this from this perspective. And this is a perspective, now, keep in mind, from a state that maintains or has huge coal reserves, right now U.S. oil consumption is about 6.5 billion barrels per year, okay.

The Governor believes that domestic production will probably be able to account for about 2.5 billion barrels of that. Okay. The oil industry will be able to maintain that kind of production. That gives us a shortfall of about 4 billion barrels per year. Okay.

The Governor has a vision of being able to make up that shortfall in the following ways: First of all, he believes that we can conserve about a billion barrels a year through conservation and efficiency programs, very aggressive ones.

He believes that biofuels, ethanol, biodiesel, various types of biofuels could make up about a billion barrels a year. So that leaves us with about 2 billion barrels of shortfall still.

And the Governor believes that coal-to-liquids ought to be something that's considered an important player in America's energy independence quest. I know that George from NRDC today was not a strong advocate for liquid fuels development. But, you know, in reading through the 2005 Integrated Energy Policy Report, you know, I noticed in the transportation fuels section there's, you know, no fuel's really a panacea. And I think we've heard that today when it's come to a lot of the presenters about energy. It seems like there is no silver bullet.

And the Governor believes that coal-to-liquids definitely has a place in the energy transportation fuel mix. And so he's a strong advocate for it.

And recently Montana's legislative session just ended; and the Governor's flagship legislation was called the clean and green tax incentive program. And that passed just very recently.

And in it, it provides significant tax breaks for clean and green energy facilities, coal-to-liquids, IGCC plants, biofuels, geothermal. All those have gotten some significant tax deductions or tax reductions, permanent property tax reductions, to help incentivize that development.

We've also got a provision in that for transmission lines that can have a huge reduction in property taxes from them from 12 percent to 2 percent. And, in fact, an abatement period for 15 to 19 years, all the way down to 1.5 percent. So the Governor is pushing aggressively for economic incentives for clean energy development in the state. When I say transmission lines, they have to have a minimum percentage of power that comes from clean sources in order for them to qualify.

And so the thresholds do involve CO2 capture and sequestration. These have to be new investments. These incentives can't go into existing facilities. And they have to pay the prevailing wage rate.

So the Governor is putting his money where his mouth is, and the Legislature has followed suit with that. And so we have some important incentives in the state that are available right now for clean energy development.

So, this presentation, what I'm going to talk about then basically are these -- while we have an oil and gas production, I mentioned, that is fairly significant in the state, we're not going to talk about that today. And we're going to focus on coal, of course, is going to be most important in this discussion.

We're going to talk about wind and biofuels. I'm going to talk about wind first. And the reason I want to talk about wind is that wind and coal, we think, can go hand-in-hand. Because wind provides, as I mentioned earlier, a very clean resource; but because of its intermittency, needs -- a lack of firmness, we need backup power for wind to be an effective energy source.

And so coal and wind can go together well. And so let's talk about the wind resources in Montana.

This map shows the U.S. annual average windpower potential. You'll notice that the darker the blue the better the wind. And you'll notice that red oval is around the State of Montana. And Montana, then, really has the greatest wind resources in the United States. So much so that let's take a look at what our wind power potential is in Montana.

As expressed by the DOE, we have 116,000 megawatts of potential wind power in the State of Montana. Let's compare that then with California. California's windpower potential is about 6770 megawatts. So you can see that Montana has an absolutely enormous windpower potential. Actually 17 times greater than that of California's. And, in fact, California has developed about a third of its potential right now. You've got about 2360 megawatts online from wind power. Whereas California can really then only develop another 4400 megawatts and you'll be 100 percent developed in the State of California.

While Montana's only developed 146 megawatts of that huge wind potential, which is only one-tenth of 1 percent. So, as you can see, Montana has an immense ability to supply windpower to states like California.

Our windfarm activity is picking up. As I mentioned, we only have 146 megawatts online right now, but those red dots indicate where existing power plants are, windfarms. But the blue and green dots show where they're being proposed and planned throughout the State of Montana. And so that activity is occurring right now. And will continue to do so.

Montana's done some things in terms of commitment to windpower. We've got a 15 percent renewable portfolio standard that needs to be reached by 2015, so that's an instate incentive. Montana has seven tax incentives, so we've got things. And Senator Baucus from Montana had passed a clean renewable energy legislation at the federal level. So those are our wind resources. And so, like I say, those are the kind of things that we're going to blend with our coal.

Montana also has great biofuels potential. We've got some huge assets for biofuels in the state. We've got a large land area. As I said, we're the fourth largest state; we include Alaska in the mix. So we've got a lot of potential to grow energy crops. We've got 16.5 million acres where we could grow oil seed or grain crops; and 19 million acres of nonreserved forestland which we could use for biomass energy. So Montana has some great biofuels potential in the state. But it's only potential right now. We have no ethanol production in the State of Montana right now, in spite of the fact that we have a great potential.

Now, Montana is definitely coal country. And we are -- but I think Montana's coal statistics are really in many ways misunderstood. We have huge coal reserves, but we haven't developed a lot of them to this point. We are a large coal producer, but we're well behind Wyoming. Wyoming produces about ten times the coal that Montana does.

We have huge reserves; 120 billion tons. That's 28 percent of the nation's coal. And about 8 percent of the world's coal are found within the boundaries of the State of Montana. We do produce about 40 million tons annually.

Our coal is located, as you can see on these next slides, in the eastern part of the state. Those are bituminous coal reserves, the grey; sub-bituminous in the brownish color; and then lignite coals are in the far eastern part of the state. All that coal is located in that prairie provinces, or prairie section of the state.

It's a semi-arid area with very low over-burdens oftentimes. I know that there was a picture earlier of kind of a huge open-pit coal mine. I know that the overburdens in Montana, most of this mining that goes on in Montana right now is strip mining of that 40 million tons. New mining would be strip mining. Usually the overburden is not that thick on Montana coals. It is fairly easy to get at.

I've been in the areas in eastern Montana that have been mined and reclaimed, and there's very little difference that you can tell between the undisturbed areas and the areas that have been reclaimed.

So what are the markets for our coal in Montana? Well, it can be shipped by rail to market which is done significantly in the state right now. It could be made into coal-to-liquids products, diesel and petroleum. It can be made into natural gas, as we talked about. There's a gasification plant -- and we've talked a lot about gasification this morning. And then, of course, it can be made into electricity.

And so the Governor's really advocating for more of the plant development to occur in Montana, to add value to the coal that's mined in Montana. Because as you can see, it can be shipped out of state, but little value is added to it.

The images you see on the screen now are of a gasification plant. In fact, that's the Beulah Plant, located near Bismark, North Dakota. That's the plant that's involved in the Wayburn project that we talked about earlier that's demonstrating enhanced oil recovery using carbon dioxide. It comes to about 5000 tons a day, about a third of their production of CO2 is used for enhanced oil recovery. We'd like to see that kind of development that you see here occur in Montana.

We've been working with major gasification technologies. It's technology that has a number of players. You recognize some of those names there. It's a proven technology with the exception of maybe some of the things that our friend from FutureGen mentioned in terms of utilizing more pure streams of hydrogen. But gasification technology is fairly well understood throughout the world. There's over 100 in use, mostly in the chemical industry. But using it for power is relatively new.

This is a quick slide just showing how the coal gasification to syngas works. I won't spend a lot of time with that because we had a lot of discussion about that. But suffice it to say it is a chemical process; doesn't combust the coal as directly as pulverized coal plants do.

The Governor has been an advocate for coal-to-liquids development. As I mentioned earlier, he could see coal-to-liquids is playing a very significant role in the United States becoming less dependent, or even having no dependence on foreignly produced oil.

And so the images you see on the screen are the coal-to-liquids facility in South Africa, the SASAW operates, they've done that since the 1950s. And so Montana has that potential. Those are the major technology providers for liquefaction.

And again, in terms of process, it's somewhat similar to the gasification. In fact, gasification is really a part of CTL and is inherently cleaner.

This image you see now on the screen shows you where we have identified six top sites for coal development in the State of Montana. Those are the red circles that you can see. The green circles indicate where we're getting private sector interest in those sites. And, in fact, there's another one farther to the west near

Geyser, Montana, that wasn't one of our top-ranked sites, but it has a very active coal developer interested right now.

So those sites that you see on the screen there, we think really have the greatest potential for coal development. And they are in the far eastern portions of Montana, generally in that semi-arid prairie area of the state.

The areas that you see with the X through them show projects that are very very -- are more advanced than any of the others, and have actually even some public announcements. In fact, in October of last year, Montana had -- the Governor got to announce the first coal-to-liquids plant that would be built in the State of Montana; and in fact, would be one of the first coal-to-liquids plants in the United States.

It involves DKRW, which is an energy company out of Houston. They're partly owned by Arch (phonetic) Coal, which is the second-largest coal company in the United States. It's located at the Bull Mountain Mine, which is near Billings, Montana. The project would involve about $1.5 billion to almost $2 billion in investment to make 22,000 barrels per day of diesel fuel.

And this image shows you where that project is located. North of Billings, near Roundup, Montana. That project's in its early stages right now, pre-permitting. They see that being about a seven-year-out project.

Another project that's getting close to actual development is the Great Northern Properties Nelson Creek IGCC Plant. That's located in the eastern, far eastern part of the state. They have indicated that they will file for a coal mine permit application by the end of this year. As I've indicated there, that project is located near the town of Circle, Montana, in far eastern Montana. And their proposal is to build an IGCC power plant there, with the mine being the first step in that.

What about the economics of coal-to-liquid? The numbers that we get right now is that if oil stays at $35 to $40 a barrel, CTL can be economic.

I will mention that the Bull Mountain project, the 22,000-barrel-per-day plant, would utilize enhanced oil recovery, and would capture its carbon dioxide.

Here's some charts that we got, or a

chart we've received from Rentech Corporation. They're a coal liquefaction technology company located in Denver. They're involved in the Bull Mountain project.

These figures show the comparison of emissions output from the coal-to-liquids plant that they're proposing at Bull Mountain with average statistics for pulverized coal plants.

And so if you look at the comparison for criteria pollutants of NOx from the average PC output versus their project, you can see it's significantly lower.

Keep in mind that coal-to-liquids basically involves IGCC technology upfront. So it's a gasification plant. But then instead of taking that gas that's produced and running it through a combined cycle turbine, liquid fuels are made from it.

SO2 levels would be significantly lower, as I indicated. This is basically IGCC-type technology. And so we learned earlier today that we can extract SO2 and NOx, these type of criteria pollutants, quite effectively. This project does propose the capture of carbon dioxide. Montana, and I'll talk about it later, has some good opportunities for enhanced oil recovery as well as deep saline aquifer sequestration in the State of Montana. And we'll talk more about that. But this project at Bull Mountain would propose to utilize CO2 for enhanced oil recovery. And so particulate matter would have likewise low emission levels.

So we can see that the Bull Mountain project would utilize advanced coal technology and would be a clean technology.

So what about carbon capture and sequestration. As I mentioned the Governor has publicly stated that all coal plants, new coal plants in the State of Montana should capture and sequester their carbon dioxide.

And Montana has some great opportunities to do both EOR and deep saline aquifer sequestration.

The hot spots for CO2 sequestration are in that area circled in red there. This map comes from the Big Sky Carbon Sequestration Partnership out of the Montana State University. They're one of seven DOE-funded sequestration partnerships who are charged with identifying sequestration opportunities throughout the United States. And these are the very good opportunities that are available in the State of Montana.

As I mentioned, we have fairly significant oil production. And we have some companies, in fact the area on the screen, this area right here is owned by a company called Encore Acquisition. They're out of Texas. They own one of the largest oilfields in the United States. It's called the Cedar Creek (inaudible). It's estimated to have 3 billion barrels of oil in it. It's been pumped since 1950s. They've probably taken about a half a billion barrels out of that field. And they are very interested in purchasing all the CO2 that a local plant could give them.

And they are working closely, like with the plant that I mentioned earlier, the IGCC plant at Nelson Creek. And they basically could buy all of the output from a plant that's been proposed there. So, that's one of a number of areas where enhanced oil recovery could work very well in the State of Montana. Dr. Lee Spangler runs it.

I'm not going to spend a lot of time with this because we've already talked about the Wayburn project. And this just shows a map showing how the CO_2 is conveyed from Beulah, North Dakota, up to Wayburn, Saskatchewan. You can see that project going on right there.

A lot of CO_2 pipelines exist in New Mexico and Texas because EOR is used right now, and to a large extent using natural sources of carbon dioxide. And that's what occurs in Texas. And there's some of that that goes on in Wyoming.

Of course, Montana has an opportunity to generate a lot of electricity. And we'd like to do that in a clean and green way. Art talked earlier about an 800-pound gorilla. Well, here's another 800-pound gorilla.

Montana really is the 800-pound gorilla. Governor Schweitzer likes to view it that way when it comes to domestic energy supply, and particularly coal. As I mentioned earlier, we have 28 percent of the U.S. supply of coal.

When it comes to energy consumption pretty much California's that 800-pound gorilla. And California's legally demanding that any power that's imported into your state is going to have to be clean. It's going to have to meet IGCC standards, basically your AB-32 requires that it meets no new electrons that are coming into the state are going to be able to exceed that of a combined cycle natural gas plant.

So you're driving this industry, this IGCC industry. And the Governor's pretty much indicated, great, California, you tell us what you want and we're going to work on building that. That's what the Governor's attitude about that is.

And we heard today that carbon capture and storage looks very feasible; it looks like it can be done. The Governor's very confident that it can be done effectively, through both EOR and deep saline aquifer.

And what's important about all this is that California is really driving this, and by 2020 about a full third of your power's going to have to come from these clean sources. So, you're driving what's going on in places like Montana. And so Montana's responding to that.

Okay, so here's where Montana can -- well, this is basically where Montana's power can go, in the southeast part of the state, and can be taken to the Pacific Northwest, the southwest and California.

So as I've indicated earlier, Montana is rich in natural resources. The Governor sees energy development as being the linchpin to economic development in the far eastern part of the state where these energy resources exist. He sees renewables and fossil power as being very important to the nation.

Carbon sequestration is important to the globe. And the economic development that will occur from these energy development in the State of Montana is extremely important as well.

So, I thank you for the opportunity to present the Governor's vision on energy development and would open it for any questions if you have any.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Yes, Melissa.

MS. JONES: You had mentioned earlier that you have the tax credits for the green transmission, that there was a percentage of renewables that was associated with it. What is that percentage?

MR. KAISERSKI: I'd have to go look at the rules to see, but actually it's a graduated scale. And so the greater the percentage of renewables the greater the tax reduction. So I indicated that it would go from 12 percent to 3.

In order to get the maximum property tax reduction I think you had to carry 90 percent. But then it's graded out through that. The taxes are higher for the less green power that you carry.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Tom, for an excellent presentation. And thank the Governor for allowing you to come share it with us.

MR. KAISERSKI: Thank you very much.

MR. SOINSKI: Has anybody filled out a blue card requesting an opportunity to speak for the morning session? No. Okay.

I'd invite the four participants who are here from the morning session to take a seat up here at the table.

(Pause.)

MR. SOINSKI: Thank you. Commissioner Geesman has stepped out of the room. I was asking him about what issues he thought was really important and what big question or take-away we'd like to have.

One of the things he said is that he'd like to know really what we can expect to happen in terms of energy supply based on coal, or, of course, could be renewables, also, in the State of

California by the year 2020, recognizing that we're not very good in predicting what's going to happen in 2030 or 2050. I was wondering if there was any comments on that.

The other thing is we have very different views on, you know, whether coal is clean; whether coal is not clean. And really what the pace of technology development is going to be, and where we are as to maturity of technologies ready to deploy, which comes into the 2020 question. I was wondering if anybody would like to tell the Committee what the vision is of what supply to California from coal reserves is going to -- how it's going to develop in the next 13 years.

MR. KAISERSKI: I might mention that the vision that the Governor has for providing energy from Montana is going to require that in terms of electricity that new transmission be built. Because largely Montana wind reserves, for example, and to a large extent really our coal is stranded because the transmission capacity doesn't exist to really export much more power out of the state.

Montana currently exports about half of

the power it generates. It generates about 3300 megawatts a year, and it exports around 1600 of that. A lot of that goes to the Pacific Northwest.

And those transmission lines are, by and large, full, although there is movement to try and study ways that the transmission lines that exist can be better utilized. But we are going to have to develop more transmission lines to be able to move power out of Montana.

And if that's the case, we believe that the coal can play a significant role utilizing IGCC, carbon capture and storage. And we believe we have the opportunity to effectively do that in the State of Montana. We have the opportunity to mix that with wind, which we have those huge wind reserves.

And we think that we could provide significant amounts of clean power to the State of California by 2020. In fact, a project that's being proposed right now for building a transmission line to California, it's called the Northern Lights project. It's a project of TransCanada. It's kind of a companion project or, I would say, partnering project or complimentary project to the Frontier Line project that I know you're well versed in that.

But that project would be a high-voltage dc powerline that could carry about 3500 megawatts of power out of Montana. They've proposed a second line out of Wyoming carrying a similar amount of power.

But we see a hypothetical situation of filling that Montana-based line, or originating line with, say, 2500 megawatts of IGCC coal by that time period, with about 1000 megawatts of wind. You could have some variation on that, but we could see that being very do-able in the State of Montana.

MR. DALTON: I'd like to add that I believe there will be a number of pioneering projects. Two weeks ago I testified in the House to the extent that while there is no silver bullet, which several people have said, we believe there's an arsenal of new technologies being developed around the world, a variety of technologies for coal and for coke gasification.

Some of which you're seeing proposed in California. The more clean hydrogen power project, as well as the Carson energy power project, I'm still not used to saying it that way, sorry. As well as a number that will be proposed in the west.

We see that by 2020 you will have not only seen FutureGen in place, plus four years of injection or thereabouts, plus follow-up years of monitoring, which you can see that that technology and integration would be folded back into the next round.

And as we've seen in that learning curve, if you will, the technology -- curve, that that will then be worked into the next round of plants. I'll talk this afternoon about some of the post-combustion work we're doing in Menlo Park, here in California. We've been working on it for about three years looking at post-combustion technologies.

We're not saying that's the answer. We're saying a lot of people are working on many many different sources of technologies that vary from biofuels, production from solar, through algae, extraction of biofuels, and using the residual biomass eventually in some sort of (inaudible). All sorts of ideas. Some of these will work, and some of them won't.

We really do believe that this next ten years we need to get on with the job of testing, demonstrating, and also find out how to deploy some of these new technologies and learn from these initial pioneering efforts.

DR. PERIDAS: I'd just like to add here that this can all be seen as a means of giving -- coal. It can be done, and it can comply with carbon emissions standards. But there are a lot of better things that California could and should begin and is already looking at at the moment that are going to be cheaper and cleaner than the loading order I think described that very well. We do have to stick to this order of priorities. And it's going to be -- of one solution to try and maximize energy efficiency measures before we launch into a new round of major coal investments.

And by 2020 I think I fully agree that carbon capture and storage technology will be far more developed than it is right now. I sincerely hope it is. And I'd just like to point out that we should not just -- of coal, it can be done with other fuel sources, as well. Natural gas is one of them. There are different technological terms, especially with that, because of technical issues related to the concentration of CO_2 and exhaust gases and so on.

But it can be done. And by 2020 I would expect it to be more feasible. And that if we're looking at (inaudible) then that's another means of reducing emissions from these plants, as well.

But I would add to the extent we can stick to the existing loading order, we do that before launching into any round of coal investment.

MR. SOINSKI: Mr. Michael Mudd, do you have any comments?

MR. MUDD: Yes. Am I on now? Can you hear me?

MR. SOINSKI: Yes, we can hear you.

MR. MUDD: I guess, you know, my first view is I think that hydrogen is going to have the opportunity to play an increasing role in our energy life styles if our nation is smart.

The second thing is, you know, we can't sit here and paint a picture, but I think we can paint a pathway. And the pathway has got to be relying on R&D rather than the marketplace. I think we've all seen the marketplace can be harsh and ruthless and technology indifferent.

So regardless of what pathway we want to paint, if we can have a good portfolio of R&D to get there, sponsored by both industry and state and the federal government, we can drive our nation towards an optimistic answer. But if we sit back and say the marketplace will solve all, then I fear that people will get hurt.

PRESIDING MEMBER PFANNENSTIEL: I have a question for all the panelists that's sort of puzzling me for awhile now.

We talk about a year out like 2020; and it seems, from what we've heard, that the technologies for, well, IGCC and carbon capture and sequestration exist. And the coal is there. And the issue really seems to be a cost issue.

Clearly we need to do more development to perfect the technologies and that's happening. But the costs still are way up there. Are there projections for these costs to come down? We see the cost of renewable resources, for example, going down. And we've seen that over the last several years. And yet the cleaning-up-coal kinds of costs are really quite, they're high in front of us, and we see a long trend towards developing those technologies such that the cost remains fairly high.

How do you see that? Maybe, Stu, you could start?

MR. DALTON: Sure, I'll be happy to start. I agree that the cost is not trivial to clean up; and that curve I mentioned that we didn't develop is engineering curve. There actually is some Carnegie Mellon work that's shown in Edison Mission presentation that is one of the slides.

I happen to have been personally involved in some of that work as R&D for the Electric Power Research Institute in cleaning up for sulfur. That's what I did for about 30 years. And we saw the costs come down with time. Unfortunately, it does take some time.

I think what we have to do now is look at getting the technology up integrated, which right now it's not at that same scale; tested and developed so that we can prove that storage is safe and effective. And we have to have assurance so that the public will accept that. And that will take some time. It will take some time after the large-scale injection to monitor the site.

The technologies, themselves, for

capture from IGCC do exist. I'll talk about that a little later this afternoon, at relatively large scale. And at relatively small scale for post-combustion capture, even on a conventional plant.

So, those technologies are there. But right now they're quite costly. We believe that that kind of cost curve of declining costs with time and -- the dollars is real. And that R&D is the primary method of doing that. But also feeding the experience of industry back very quickly is the other key. And that's, again, what we're trying to do.

MR. KOSTRZEWA: I think all we can really make are historical analogs to what's happened with other energy technologies. And they've all followed that similar path.

And so we believe that IGCC technology will follow the same path, but there's no guarantees. But none of the other options are static either. If we say IGCC is too expensive, then for the most part what we're saying is we're going to meet all of our needs with natural gas.

Well, natural gas production in North America has peaked. And so all that incremental natural gas for the incremental power plants is going to be imported LNG. And that has its own environmental impacts; and it has its own cost and political considerations with it.

So, there aren't easy choices. Renewables, there's a limited amount of renewables that can be done within California. And, you know, if we start going out to the more expensive, more distant sources, and, you know, solar and those technologies, they're going to get more expensive, as well.

It's a difficult choice. And really, we need to explore the options and let the market decide. And, of course, California is the market. California says, we want renewables, so we sign contract for renewables. Contracts for natural gas fired capacity have been signed in the last several years, and that's what's getting built. So we're making our technology choices by what we sign up to buy.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Jeff.

COMMISSIONER BYRON: If I may, I'll make a statement and I'll ask you to respond to it. It would seem to me that given the presentations that we see today, Mr. Peridas, you know, the developing countries is where we have a significant issue we need to address. The development of technologies in this country will benefit us, but will have much broader implications outside this country.

So my statement is we're not spending enough research and development on capture and sequestration. I'd like you to respond to that, if you would, please. Go ahead, Mr. Dalton.

MR. DALTON: I would agree with that statement. I've testified to that point. And if you look at -- it's hard to say you should do this just because it's going to help, when again, the U.S. has historically been not controlling CO_2, and has been emitting more and more CO_2.

But if you look at China, India and other developing countries are interested. They're saying, okay, I want the technology to be cheaper; help me to get it to be cheaper. And then they're also saying we want that technology to be something that's useful for us, for our coal, for our situation, and in our country.

Now, we believe that it will benefit to have the technologies developed in the U.S. We're not alone. The Chinese are working with the

Japanese and other organizations these days. We don't develop technologies, and it is required internationally, they will look to other providers, or they'll develop, themselves.

So we think that the U.S. must do more to develop the technologies, pioneer them, and demonstrate them at large scale; and show that storage on our own soil is feasible to assure people that we're not just saying you go do it, but we don't want to.

MR. SOINSKI: Mr. Mudd, do you have a response to Commissioner Byron's statement?

MR. MUDD: I think that both DOE and EPRI have shown excellent roadmaps to show how we can reduce the cost of coal-based technologies; in fact, any technology.

I do want to mention that the cost increase we've seen are because metal's more expensive, and there are fewer engineers to do it. The same metals that go into the technologies that are used for renewables, I think that you would see those same painful cost increases across the table for all technologies.

MR. KOSTRZEWA: I think we should separate the CC and the S part of CCS. Carbon capture and sequestration are separate technology areas. Carbon capture is the really expensive part of CCS and the area where there's a lot of potential for research and development to find less expensive ways to do that.

I might take a little bit of an outlier position and say on the sequestration side the oil industry knows very well how to characterize what's underground, what the rock looks like, how the rock will behave, how the fluids will behave.

The think on the sequestration side we're more into the stage of we need demonstration, large-scale demonstration projects. And really, the subsurface technology is very well advanced.

DR. PERIDAS: I would agree with the statement that we're not spending enough on energy -- when you compare the amount of R&D money that goes into energy research; it's dwarfed by -- you know, spending several billions worth of that -- for a war in Iraq is not a very good way of insuring energy security and self sufficiency.

I definitely think that we need to be looking into this technology much more concertedly, and much more expeditiously. And however we differ in the assessment of DOE's efforts here, I think we should be doing things a lot faster and with a lot more urgency.

The recent MIT report also seconded that view. We have testified in Congress saying that we should be pursuing the sort of five to seven large sequestration demonstrations to learn more about what happens when you inject in excess of 1 million tons of CO2 a year and exceed certain importance of geological thresholds.

But at the same time we don't see any show-stoppers right now. Under good oversight from this (inaudible). Now, what isn't there, and this is not just a question of pouring R&D money. The question is what happens with the R&D money, what does it lead to.

The amount of investment of the private sector can bring these technologies and really dwarfs one government, federal or state, can put into this. So we should insure that the policies are there to make sure that whatever R&D money government put in that actually broaden to fruition.

And the EIA actually did an analysis and said that R&D money's going to be about eight times more effective with a company policy that insures that it's put to good use. And what we talk about here is reasons to do CCS, and that's either emission performance standards or carbon capture. In the absence of that, any R&D money that's put into this is going to be probably stifled in terms of it's deployment and development.

MR. MUDD: If I may add a comment. I think that I am concerned about the problems acceptance when we want to go to the widespread deployment of injecting huge quantities of carbon down in these formations. It's the obligation of industry and government to prove it conclusively to the general public that it can be done safely, that we understand what we're doing.

And I think that the only way that we can get there is by doing it with carefully controlled experiments that would totally suggest relying on the analogy of enhanced oil recovery. It's a different process; it's a different purpose. The monitoring is not the same. So while it has helped to get us there, I do not believe that that analogy will get us to home plate at the end of the day if we just rely on that for widespread carbon capture and sequestration.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Mudd. And I want to thank the panel for being here, for sharing your knowledge and expertise. And we'll probably see you back this afternoon.

Thank you, we'll --

COMMISSIONER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: -- reconvene at 1:15.

(Whereupon, at 12:03 p.m., the Committee workshop was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:19 p.m.

PRESIDING MEMBER PFANNENSTIEL: Thank you all for coming back. I know it's nice outside. Why don't we hand it off to Kelly to get us started.

MR. BIRKINSHAW: Good afternoon, Commissioners. For the record my name is Kelly Birkinshaw. I manage environmental research for the Energy Commission, of which climate change is a major component.

And specifically, we have a very robust carbon sequestration research program embodied in the WESTCARB program.

This afternoon I think we have a complementary set of speakers for this morning's presentations on clean coal, although we'll be focused specifically on carbon sequestration.

There's some obvious linkages between sequestration and coal, although I think you'll hear really an international perspective on carbon sequestration. And we'll also talk about terrestrial carbon sequestration, something that often doesn't get much consideration, although we have found in some of the early work that we've done that it has fairly significant potential on the west coast, particularly here in California.

Our first speaker is going to be Webcast, and so this is something new for me. We have John Gale. John Gale is the Deputy General Manager at the International Energy Agency's greenhouse gas R&D programme. He's spent over 30 years in the energy sector working on clean coal technology and environmental issues related to fossil fuel use.

He was one of the coordinating lead authors on the Intergovernmental Panel on Climate Change Special Report on CO2 Capture and Storage. He is also currently Editor-in-Chief of the New International Journal on Greenhouse Gas Control, published by (inaudible). So, --

UNIDENTIFIED SPEAKER: And I'll add, for those of you keeping score I just got this in from John. He holds a degree in chemical engineering from Bristol University.

MR. BIRKINSHAW: And so -- one housekeeping item before we turn it over to Mr. Gale, again we will have an opportunity for public comment at the end of the day. If there's anyone in the audience that would like to make a statement or ask some questions, please fill out one of these blue cards and turn it in to the gentleman here at the corner who is recording this session. Thank you very much. Mr. Gale.

MR. GALE: Thank you. It's a pleasure to be with you this afternoon -- well, your afternoon and my evening. I've very happy to give this presentation on the local development from CO2 capture and storage on behalf of the program.

I'm hoping this works --

MR. SOINSKI: Try clicking on it if you need to. There you go.

(Whereupon, a presentation was made via Webex by Mr. John Gale of International Energy Agency Greenhouse R&D Programme.)

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Gale. Really good information, the presentation. Questions from the dais? Thank you.

MR. BIRKINSHAW: Thank you very much, Mr. Gale. Our second speaker is Dr. Larry Myer. He's a Staff Scientist at Lawrence Berkeley National Laboratory, earth sciences division, where he's conducted research in geophysics and geomechanics since 1981.

He's been leading research activities, geologic sequestration since 1999. And actually holds a joint appointment at LBNL and here at the California Energy Commission, where he is the Technical Director of the West Coast Regional Carbon Sequestration Partnership.

Larry has a PhD in geological engineering from the University of California Berkeley.

DR. MYER: How do I advance it?

(Pause.)

DR. MYER: I'd like to say thank you to the Commissioners for allowing me to summarize and give an update of the WESTCARB project. This project has the overall objectives of evaluating opportunities for both terrestrial and geologic sequestration in the west coast.

And results to date show that there are very significant opportunities for sequestration in California. And I will try to discuss those in a little more detail.

So the outline for what I want to present is this. I'll start off with a little definition of what this research project is about. Then provide just a short summary of some of the regional scale assessments that we did of sequestration opportunities in the west coast, and focusing on California.

I'll then discuss some field pilots that we are working hard to get underway, and are a very important part of the development of the technology. And finally, a brief summary.

So, WESTCARB, which is the West Coast Regional Carbon Sequestration Partnership, is one of seven Department of Energy partnerships, all of which have been developed and put in place to evaluate opportunities for both terrestrial and geologic storage. And the map there shows how the United States is basically divided up amongst these various partnerships.

I'll add that New York has just recently joined one of the other partnerships, so that is no longer a white state in the map.

The Department of Energy program is a large program; it represents 40 states, I guess 41 states now, four provinces in Canada, and over 240 organizations throughout the United States.

It's been conducted as a series of phases. The first phase, which is already complete and began in 2003, was to focus on regional assessments, broadbrush assessments of opportunities. The second phase, which is now underway, is focused on small scale pilot studies. You've heard from previous presentations there's something like 20 of these actually planned across the United States over the next few years.

And then the third phase, which is about to begin and scheduled to begin in the beginning of 2008, is the third phase, which would be large volume sequestration tests, or precommercial geologic field tests.

So, a little bit more about what the WESTCARB organization is. It is a partnership; it is, however, just a research project. So not a legal entity. But it is a partnership with broad stakeholder representation. We have more than 70 organizations involved in this partnership to date.

I'll note that we have amongst these some world-class technical expertise folks who have international recognition with regard to their contributions in sequestration. And I acknowledge the California Energy Commission as being the prime contractor working with the Department of Energy on the WESTCARB project.

So, terrestrial and geologic sequestration are both options, where terrestrial sequestration is sequestration of carbon by natural process and forest plants soil; and, of course, terrestrial sequestration is CO2 source independent.

Geologic sequestration is sequestration or storage in deep saline formations, oil and gas reservoirs or coalbeds; and, of course, requires industrial processes to capture at the source and inject onsite or transport via pipeline.

The point I wanted to make here is that the technology for both of these options is available now. The tools that we need to form both terrestrial and geologic sequestration are available, making this a near-term option not only in California, but as you have heard, elsewhere. I'm not going to say much more about the terrestrial sequestration effort in WESTCARB. John Kadyszewski will be speaking a little later this afternoon and will speak in more detail about that.

I think this slide is not in -- if you're looking at your handout, is a little later on, but I advanced it to this location in the talk for clarity. I show here the California CO_2 emissions by sector from the USEPA database. And I want to point out, use this slide to show the relevance to the kinds of sequestration that we might be interested in applying in California.

And first point I would like to make is that we have a significant industrial CO_2 emission source in California in 2004, on the order of 75 million metric tons per year. As well as an electricity generation source instate.

So, in California we've heard -- and we have heard a lot of discussion today about coal, I just wanted to make the point that in California we should look at the industrial sources, as well as the utility power sources as something that we need to be thinking of when we do geologic storage.

And then --

ASSOCIATE MEMBER GEESMAN: Larry, --

DR. MYER: Yes, --

ASSOCIATE MEMBER GEESMAN: -- can I interrupt and ask if the refineries are captured in the industrial column or the transportation column?

DR. MYER: I believe they're captured in

the industrial column.

ASSOCIATE MEMBER GEESMAN: Thank you.

DR. MYER: And then in the transportation column, which is the mobile sources, we have the most significant contribution to the emissions profile. And a point worth making here is that the terrestrial sequestration opportunities can, in fact, deal with some of these sources such as the transportation sector; whereas the CCS that we've been talking about to date would not be able to deal with CO_2 from the transportation sector because of the problems of capturing the CO_2 from all these mobile sources.

So, in California we have, and should be, looking at multiple types of sequestration opportunities.

Going to spend most of the rest of the time talking just about CCS, or geologic storage. And I begin with outlining the primary geologic storage options for California.

And the first are oil and gas reservoirs. And one could consider storage with enhanced oil recovery or enhanced gas recovery. But, of course, you need not do enhanced oil recovery or enhanced gas recovery. You could use these reservoirs for storage only. So it's worth noting that we have that option.

And then finally the largest potential opportunity for geologic storage is the saline formations. And there are no economic opportunities available in saline formation for offsetting costs. So those would be storage only.

And one final comment with regard to this is that from a geologic perspective, oil and gas reservoirs represent localized regions within saline formations where hydrocarbons have collected.

So if you take sort of the 10,000 or 30,000 foot view of the geology, there is no distinction between oil and gas reservoirs and saline formations. They are the same fundamental beast. It's just that oil and gas collected in localized areas in the saline formations.

A summary of the work that we did in WESTCARB to evaluate the major geologic storage opportunities in California are shown on this slide. And on the right is a picture of California and the light green colors show the location of sedimentary basins, or those basins which contain saline formations, which are the most opportune places in California for storage of CO_2.

There are other basins in California; and those are shown in light grey. Those are not opportune places for storage of carbon dioxide because they may not have sufficient depth; they may not have seals in the formations which would hold the CO_2 in place.

So one of the things we did initially was to screen the formations and basins in California to evaluate those, which would be the most opportune locations for storage.

Another thing that you see on this map are the red globs and the brighter green globs which represent the gas fields in red and the oil fields in darker green. And you can see that they are located in some of these sedimentary basins. And therefore reinforce the comment I just made about the co-location of oil and gas fields and sedimentary saline formations.

Also shown are the locations of the power plants, as well as major industrial point sources in California which show that these sources are broadly distributed and co-located, generally speaking, with available sedimentary basins for disposal.

The amount of potential storage in saline formations is, indeed, very large in California. With the Central Valley alone having the capability of storing from 50- to 250-billion tons of CO_2. Just the gas reservoir capacity, itself, if you just look at the storage capacity of the gas reservoirs would be on the order of a little less than 2 gigatons; oil reservoirs representing another 3.6 gigatons of storage potential.

This is a cross-section, a generalized, geologic cross-section of, in fact, the southern Sacramento Valley. And I show it to illustrate the scale at which these very broad estimates were made of the storage capacity in the geologic formations.

And the yellow on here represents basically those regions in the subsurface which would be -- are sandy, and would be potential targets for geologic storage. The blue-grey are the seals which are necessary; and they're sealing low permeability, low porosity formations which are necessary to hold and keep the CO_2 securely stored.

And we are continuing, as part of the WESTCARB project, however, to refine this map. The scale on this is very large. Basically east/ west going from the foothills to the coast ranges. And the point I wanted to make here is that the geology's actually significantly more complex than this. This is a very large scale and gives you a first-order assessment of the total capacity. But you can't stick a straw in anywhere and expect to be able to store CO2. And so the geologic survey is continuing to do a more refined assessment of some major target formations including the Mokelumne and the Starkey, to better aid in actual site selection that people would be interested in doing.

Costs, of course, have been mentioned; and are very much of an issue. And we developed this marginal cost curve which we are going to refine. But it provides some baseline information about the potential costs of doing geologic storage in California.

And we can see from this cost curve that $40 a ton is a figure which is reasonable for the costs of doing geologic storage if we are looking at retrofitting existing sources in the state;

retrofitting them with available technology. Pipelining that CO_2 to oil reservoirs where you could do enhanced oil recovery and taking some credit for the sale of that oil.

So, as I said, we will be looking now in the future at refining these and looking at costs of new builds, as well as retrofitting.

One more link to the terrestrial work is that there are, in the future, significant opportunities in California for storing CO_2 from operations which use biomass for either energy production or biomass-to-fuel.

Shown here on this graphic is a picture of the major sedimentary basins which you have seen on the previous overhead. In addition to that are shown the forested high and very high fire risk.

And I just show this to show the co-location of these resources, forests in high and very high fire risk represent a source of biomass. And, once again, John Kadyszewski will talk more about this opportunity in the future. But I wanted to show that this in California represents a significant, and I think unique, opportunity that we have in California for linking both terrestrial and geologic storage.

One of the other missions of the WESTCARB project was to raise public awareness. And this is continuing to be a major part of our work. And as you're well aware, climate change related to legislative initiatives are becoming abundant in California. And it's our job to provide information to policymakers so that they can judge how to move forward with this legislation.

Media inquiries are increasing. And WESTCARB is meeting with state and local leaders on a regular basis to provide information. And, of course, we have a dedicated project website, westcarb.org.

So turning now to the pilot scale storage projects. And I show a map of the entire WESTCARB region. And to illustrate that we are working not only in California, but in the surrounding states to perform both terrestrial and geologic pilots. But, of course, I'll focus, in my continuing remarks, just on the pilot that we're doing in California.

But these are small scale pilots, and they're vitally important to the overall objective of developing this as a commercial technology. The small scale projects are representative of the best regional sequestration options. And they provide a site-specific focus for testing the injection technologies, assessing the capacity of the local region, determining costs, assessing risks, validating monitoring methods and establishing regulatory procedures.

And even though the amount of CO2 is not large associated with this, they represent a vital link between the very large scale and commercial scale tests that need to be done, and the science.

So I'll now describe briefly the pilot that we are planning not far from here, about 30 miles from here, at the Thornton Reservoir. And it is called the Rosetta Resources CO2 storage pilot because we are working with an industrial partner, Rosetta Resources, as our lead partner.

And the overall objectives of this pilot are to validate the sequestration potential of the California Central Valley sediments, which I'd already indicated to you was a prime location for sequestration in California.

We have a second overall objective which is to gain insight into the viability of CO2 storage and enhanced gas recovery. We are well aware that CO_2 can be used for enhanced oil recovery; it has never been used commercially for enhanced gas recovery. And we wanted to make some measurements to begin to look at the viability from a technical perspective of doing that.

As I indicated, these are small scale tests where we inject up to 2000 tons, at, however, a significant depth, or meaningful depth for sequestration. In this case about 3400 feet below the surface.

And certainly another focus is on monitoring. That is application of technologies for evaluating where the CO_2 is going and what it is doing in the subsurface.

What will we accomplish with this pilot test? First of all, we'll show that CO_2 can be safely injected into deep subsurface geologic formations. That it can be securely stored in geologic formations. That computer models can predict how the CO_2 moved into and interacts with the reservoir rocks and fluids in the rock.

That there are multiple types of measurements which can be used to monitor the CO_2 in the subsurface and detect leaks. And then that we will help clarify state and regulatory framework, as well as other legal issues. These are very important objectives of the test.

I'm now going to take a little bit deeper dive than I normally would with regard to the technical aspects of what we're going to do. Because we often end these talks with these very general comments about the existence of technology and tools to do things, I wanted to just take a little deeper dive and actually tell you and show you some of the technology associated with doing pilots, and of course, technology that's relevant to the full-scale application, as well.

And so in this pilot at Thornton, what we will do specifically is assess the seal integrity. I've spoken that we target formations where there's a low permeability rock layer above the reservoir which we call the seal. And so we want to assess the integrity of that.

We want to assess the spatial extent of the CO2, how far it spreads in the subsurface; the storage capacity; how much we can put in; the injectivity, how easily can you put it into the subsurface.

And then in the gas reservoir we want to specifically study the mixing of CH4, which is methane, with the CO2. That's the real issue associated with whether you can do enhanced gas recovery. It's answering the question about whether it mixes too much in the subsurface, and basically contaminates the methane too much.

The graphic on the right shows the schematic description of the pilot test, which shows geologic layers in two wells which intersect those layers. And it says pilot test 2, and pilot test 1, which means that we're going to do two different injections into the subsurface.

So in one well we will inject the CO2. We have the second well as an observation well. And we will do, as I said, two separate injections first into the saline formation, and secondly into a small depleted gas reservoir.

The kinds of measurements include down-hole measurements of pressure and temperature; fluid sampling; wireline logging; vertical seismic profiling; shallow groundwater and surface CO2 sensor measurements.

We use computer simulations, as you see on the bottom right, to begin the process of designing the tests that we do in the field.

I mentioned one of the objectives was to help clarify the regulatory framework. And we are doing that through working with both USEPA Region IX and the California Department of Oil and Gas and Geothermal Resources.

California is underground injection control mixed primacy state, both the state and the EPA have primacy.

And so in this case we have established that for our pilot test the California State DOGGR will have primacy in the gas zone injection test whereas the USEPA will give us a class 5 underground injection permit for the saline zone test. Both agencies have been very supportive in working with us to define the path forward.

Now, just the last couple of slides. I said I was diving deep into the technology, so here's the kinds of measurements that we would do, the approaches we would take to assess the integrity of the seal overlying those formations in which we inject the CO_2.

We do analysis to establish that we are not going to fracture the formation, that's geomechanical analysis. We monitor the pressure and water quality in the shallow zones above the injection zone. And then we obtain down-hole measurements, geophysical well logs from the injection and the observation wells before and after CO2 injection.

And on the right you can see the kinds of instrumentation and equipment that we place in the wells to enable us to do that. You can see that we put packers, or these are -- into the bore hole to isolate the intervals. And you can put pressure sensors down into the well, tubing down into the well to make fluid measurements.

Over on the right is a geophysical log that is run by Schlumberger. It's called reservoir saturation tool. It was developed for the oil and gas industry to tell them the proportion of oil and gas and water in the reservoir. They have adopted it, or adapted it, I should say, to provide information on the relative saturation of the CO2.

An example of the kind of adaptation of commercial technology from the oil and gas reservoir that we -- oil and gas exploration and production business that we bring to bear on the CO2 issue.

In order to look to evaluate the spatial extent of the injected CO_2 we'll use fluid sampling. We will also use seismic techniques. And I'd draw your attention to the one called vertical seismic profiling there. That is you have a source of acoustic energy on the surface, and it literally vibrates, or you can use small dynamite charges. And then in the well you put sensors to sense that vibratory motion.

And so the black line represents the path that the energy takes. And then you use the results of the measurements made by those sensors to evaluate both the geologic structure and the presence of the carbon dioxide.

And I show a picture of a result using that particular technology. And it was conducted at the Frio test in Texas. It was -- the Frio test was one in which we injected 1600 tons of CO_2 into a saline formation. So it was basically the model for the tests that we will be conducting out here in Thornton.

And the seismic information is displayed, as you see, by these horizontal colored bands. And if you compare the left-hand side with the right-hand side, and you look at the band which says Frio reflection, you'll see that the colors are a bit brighter than they are on the left.

Well, this is a sort of a dramatic illustration of the use of this particular seismic method to map the extent of the CO2 plume. And it's exactly what we want to try to do at the Thornton experiment. We want to see if, in the type of geology that we have in Thornton, if we can be as successful as we were in the test in Texas.

So, with that, I'd like to close with just a summary. There's major opportunities for terrestrial and geologic CO2 storage in California. Linking terrestrial and geologic storage may provide unique approaches for addressing California mobile source emissions.

Public awareness of CCS increase significantly, but there's much more work to do. Small scale phase two pilots are providing essential experience for regulatory clarification and project scale-up.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Very good. Questions.

COMMISSIONER BOYD: Yes. Larry, you

referenced the fact of not quite sure what the saturation level might be for CO_2 in methane, or what that might do. And I was just wondering if there's been laboratory tests, bench tests of some kind to try to get an idea of what possibly would happen with that.

DR. MYER: Sure. There has been some laboratory work. There's been -- a lot of the motivation for this has been numerical simulation. And which show that you should be able to displace methane with CO_2 because of the contrast in physical properties. And I believe that laboratory experiments have demonstrated the same thing.

It needs to be demonstrated at the field scale because the hydrogenity at the field scale is significantly more than that in the laboratory. And so you really need to do it at the field scale.

COMMISSIONER BOYD: Thank you. You referenced possibly getting more gas out of the well by injecting CO_2, i.e., the analog being the oil recovery. Has there been any field test of that type of activity before?

DR. MYER: I'm not aware of any tests

that I've seen a paper on. In Europe, -- I wish John was still on the call -- there is a -- they are also conducting a enhanced gas recovery pilot using CO_2. It's offshore of the Netherlands.

But I'm not aware of preexisting published work on this.

COMMISSIONER BOYD: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Yes.

ASSOCIATE MEMBER GEESMAN: At the site screening level, what role has seismology played in your evaluation?

DR. MYER: Seismology has a role to play in site screening if there are seismic data available. Because it provides a much better picture, if you will, of the subsurface conditions than if you don't have it available.

Site selection and site screening is a process which will have multiple stages. And whether or not we have to have seismology as part of a site selection process is something that is part of the assessment that we're trying to make through additional work.

It provides additional very important information. Whether or not you always have to have it is a question. Probably not.

ASSOCIATE MEMBER GEESMAN: How do you approach the question in terms of your anticipated future work?

DR. MYER: What we want to do is provide information which can be used to set up protocols for site selection. And that information is, in part, available from the seismic databases that are out there.

When I say you don't always have to, there are areas which have been so well drilled, if you will, there are so many preexisting wells that you gain little additional information from the seismic information.

So the process of site selection is one of developing general criteria which should be met for these sites. And you can, if you have a lot of information preexisting from wells, you could use that. If you have seismic information you can use that.

The idea, though, is to be comfortable that you have a very good understanding of the subsurface geology, the existence of the seals, and the reservoirs.

ASSOCIATE MEMBER GEESMAN: In the mapping that you showed, did you employ even some rudimentary seismic criteria to either rule sites in or sites out?

DR. MYER: This mapping that we're doing is not mapping to select sites. It's to look at general criteria and, in particular, look at the existence of, well, just the existence of seals and the depth of the formations, and whether they pinch out.

So, we have used very little seismic information because of the large amount of well bore information which is already available for the Central Valley. The geologic survey has been working at a scale where the well bore information provides sufficient data for making these evaluations.

These are not site selection studies, in that it provides a greater -- it's the next scale down, if you will, from that general picture that I showed of the subsurface providing additional guidance. When one would actually select a site, there would be additional studies needed.

ASSOCIATE MEMBER GEESMAN: What about outside the Central Valley? I think specifically southern California and some of the areas that have previously experienced quite a bit of oil development over the course of at least the latter two-thirds of the 20th century. To what extent does the existence of known earthquake faults factor into your review of what's an acceptable area and what's not?

DR. MYER: We've generally said that we wouldn't site these projects on active earthquake faults. That, in fact, is a conservative statement. One of the -- we have said, in addition, that we would consider that oil and gas reservoirs are good places to store CO2 because they have demonstrated their ability to keep these buoyant fluids in place for millions of years.

In the Los Angeles Basin there are active fault zones which form the boundary of some very productive oil and gas fields. The fact that a fault exists does not mean that you have a poor location for a CO2 storage site.

In fact, the existence of an active fault does not necessarily mean that you have a poor location, as evidenced by these oil reservoirs, which are adjacent to active faults in the L.A. Basin.

So, a conservative approach is to say that we would avoid active faults, all together.

I'll say that we would not want to have a selection process which avoided faults all together, because faults represent very often the structure by which fluids are actually kept in the reservoirs. So we would not want to have criteria which avoided all faults.

What we have to do is evaluate the individual characteristics of the site that we have to assure ourselves that we don't have leaking structures.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions? Thanks very much, Larry.

MR. BIRKINSHAW: Now we're going to shift the focus a little bit and start talking about terrestrial carbon sequestration in some detail.

(Pause.)

MR. BIRKINSHAW: My apologies, Stu. I think I had you switched. Our next speaker is from this morning, Stu Dalton from EPRI, who's going to be talking about capture technology.

MR. DALTON: No problem. It would have been a very short talk.

(Laughter.)

MR. DALTON: Since that's not my field of expertise. And I wish it were as easy as the diagram. The diagram is actually an illustration from something I can recommend for bedtime reading. This is a recent Journal article. The CO2 capture and storage is the feature article in this issue of the EPRI Journal. It's available to the public.

But capturing it in a Mason jar is probably not the technology of choice, as much as we might wish it were.

Going to talk a little bit about capture; a little bit about the international perspective on clean coal, and then a brief discussion. I broke this into two pieces.

The key message here is that we believe carbon capture and storage is an important contribution in almost every projection. We heard earlier about the Wedge analysis. We've seen IEA's analysis. Many others have said it's very important to have carbon capture and storage.

And, again, we'll talk more about the technology choice on different coals, elevations and site conditions. I'll talk about the RD&D that's needed. And especially the large-scale testing very soon, the storage demonstrations, much as we've heard, will be done in the third phase of the regional carbon sequestration partnerships. As well as advancements for materials for advanced gas turbines, higher efficiency boilers and using hydrogen -- advanced turbines using hydrogen to meet the cost and efficiency goals that we think are required.

We believe that the costs may be high and that there are things like incentives that will probably be required to make it all work. These incentives or stringent control requirements are the kinds of things that will make CCS competitive.

To visualize the three areas it's almost as if they were -- I used to say, two issues. Cost and energy use of capture and the assurance of storage. But now I'd add a third. And it's come out in discussions of the Carson Project and others, where the societal concerns are that third set of issues.

So the three sets are in capture you start with the plant efficiency and how efficient the overall process is. And that reduces the amount you have to capture, if it's a very efficient process. The capture technology, itself. The pilots that have been done worldwide. And now demonstrations that are needed. These are all areas that we feel have a lot going on.

As well as confirming long-term tests. You heard just a moment ago about some of the different geologies that might be available in California, but there are many geologies being looked at nationwide. Not everyone has saline aquifers -- saline reservoirs. Many places have to look at other geologies or pipelines some distance.

And then liability, health, public acceptance are certainly issues that must be addressed and are being addressed in things like the regional partnerships.

The options that I mentioned earlier this morning on improving efficiency and capturing CO2 is the capture approach. And the challenges for IGCC tend to be the cost and integration of the pieces, as well as storage. And you'll see that the storage or sequestration is a theme throughout the challenges for all the technologies. Improving efficiency, capturing CO2, again the same sort of issues on the approach. But then integration of capture is probably the first element of pulverized coal. The energy penalty for capture of CO_2; and again, storage.

And then for oxygen firing, one of the issues is oxygen. Takes quite a bit of energy to distill air, to get oxygen. A lot of energy, a lot of questions on how to do that. And the technology for O_2 is one of the keys for oxygen firing.

The generalized approach, and we've heard some about this, I'll just focus in on the differences. You saw a diagram earlier today without capture. Here you've added another couple of steps.

You've added something called a shift. The shift takes carbon monoxide, CO, and water vapor; combines them at high temperature in a shift reaction giving you CO_2 and hydrogen. It's not alchemy; that's how you get hydrogen from coal. That's how you can have -- the factoid for the afternoon is 1 percent of a 500 megawatt plant is enough for 10,000 hydrogen vehicles, 1 percent of a 500 megawatt IGCC plant. Quite a bit of hydrogen.

You get that by the shift reactor. And then recover sulfur and then recover CO_2. There are a variety of ways that this can be done. Pressurize it up to pipeline grade, dehydrate it and off it goes.

There are plants today operating. I said I'd mention this, and we've heard a little bit about one. And you can physically see in the picture here how big the pipeline is. This pipeline next to the person who's about my height, I guess, is -- you can literally get your arms around it. And that's for 2.7 million tons per year of CO_2.

It's compressed to the point where it becomes something called a supercritical fluid; very dense; about half the density of water.

The biggest one of these is the one in the pipeline in the U.S. And that's the 2.7 million tons a year. Now if you translated that to a power plant that would be roughly equivalent to a 340 megawatt power plant.

There are three nonpower facilities gasifying coal. Coffeeville, Kansas. In fact, that's where the old Texaco gasifier that was used in the Coolwater Project out in California went after the plant was retired. They took the gasifiers and sent them off to Kansas.

They make ammonia and urea at that plant. They capture CO2 and use some of it in the manufacture of urea, in fact.

Eastman where they make many things. But the chemical intermediates are made after they've gasified and cleaned up the coal, syngas; and then it's synthesized into a number of products. And the Great Plains, which is in the illustration.

The pieces are offered commercially. They've really not operated in a integrated manner with all the pieces working together.

For pulverized coal today, again there are some installations. Here the chemical plants are in back of the power production. The reduction of NOx, ash, sulfur are pretty much conventional. And then right now the conventional process is monoethanolamine, or MEA for short.

The very simplified diagram to the lower right shows the way this is done. You absorb it in a tower. That now is a -- has the CO2 captured. And then you have to use a lot of energy to so-called -- in the so-called stripper to take out the CO_2.

In chemical thermodynamic terms, anything that likes to catch it doesn't like to let it go. Anything that likes to let it go doesn't like to catch it. And, in fact, we've never found the perfect material that likes to catch it and can easily let it go. That's the holy grail of a lot of our research worldwide, is to try and find the best combinations and the best way to integrate energy to cause low energy penalties and low costs. There's a lot of work going on in that area.

With natural gas it looks remarkably the same for the back end. Because you're still looking for something to capture. Now, with natural gas, instead of being 13 percent, 12 to 14 percent CO_2, for coal the amount of CO_2 in the gas you're talking 3 to 5 percent CO_2.

What that does is it gives you less, again in chemical engineering terms, driving force or it's harder to capture, it's more dilute.

So, do many of the same steps. You reduce the NO_x; you have a relatively clean gas to begin with. And you do something like monoethanolamine.

But there are other processes. And I even use the byline, anything that likes to capture does not like to let it go. We've done a lot of work in that area. Others have done a lot of work in that area. There are pilot plants around the world looking for the perfect material.

Fluor, Kerr Mcgee, MHI have built up to about 300 tons a day of capture on the back end of plants. It takes about 10,000 tons a day from a 500 megawatt plant. So you can see the scale is a little different.

You have to make it very clean. The plants that are operating today have caustic scrubbers to remove the last little bit of SO2 because every little bit of SO2, sulfur dioxide, that comes through reacts with the material. Creates something that is called a heat stable solid. All that means is it really doesn't like to let it go anymore.

The chemical reaction doesn't occur to release that. So you've inactivated it. So now you've got a waste material and you're having to make up the absorbent.

The large steam uses are again the big issue. So you could have, if you use this technology, a large net power reduction. So, we're looking for options. Some of which have been tested here in California.

About three years ago we started testing one using a chilled ammonia scrubbing technology that is being tested in Menlo Park, California, still with cofunding from Allstom and Schtott Oil. And we've been testing that now about three years.

In the interim Allstom licenses on an exclusive basis for commercial use. AAP has announced an $800 million commitment to this technology. And also to oxyfuel. And we're continuing to look to pilot this; bring it up to full scale in steps.

But what's operating today you can literally get an idea of the scale with this photograph. That's about the equivalent of 10 megawatts. And what's in the circle there is the tower. That looks pretty big for 10 megawatts because these are fairly large towers. But that's roughly a 10 megawatt slipstream off of a conventional plant.

Right now the CO_2 is sold at food grade for things like freezing chickens. In fact, I think we see the commercials all the time for those same chickens that you don't want to be in other states. And if you put a tube and expand CO2 into the chicken you don't get an effervescent chicken, you get a chicken that's flash-frozen by the expansion of the CO2, and you get refrigeration instantly.

Making soda pop and baking soda. The baking soda is made in California at Kerr McGee in Trona. So, we've got a number of different uses for CO2. Right now, anecdotally I've heard this in testimony that it's about $140 per ton to make that CO2 from these type of technologies at this small scale.

Again, we've got some pilots under development. And we've recently done an assessment looking at the technologies for CO2. And looked at a variety of technologies. There are all sorts. We're not sure which ones ar going to win out.

Adsorption, there are many different ideas for different things that might be used to absorb adsorption; metal organics, customized lattices, zeolites, different micropores and membranes for separation, biological means, algal growth, cyanobacteria, all sorts of different things. Even cold separation, which sounds like a high energy use, and I'm not sure that all these will make sense when they finally work out.

Some of these are at that early part of the curve you heard earlier. And we don't yet know all the issues.

Will any of these meet the DOE goal of less than 10 percent energy penalty and less than 20 percent cost increase? We think that there probably are some in the next five years approaching one of the goal and it might take up to ten years to bring all these new ones along where they can meet both of those goals. Again, we're trying to move those along as fast as we can.

Some of that you can see a picture of here from the work in Menlo Park, California, at the SRI lab where we're looking to confirm the thermal balance and provide guidelines for first pilots. And then the larger scale design. You have absorbers, towers, tanks, looks like a lot of chemical engineering hardware because that's what it is. And we're looking at better absorbers.

This one lets go pretty easily. But it doesn't like to catch it quite as well as we'd hoped. And so the absorbers have had to get a little bigger.

There's not only plants in Europe, we put together a knowledge base of a number of the projects. These happen to be gasification projects. And about 15 that we have in our database that we've taken a look at have aimed at capture and storage from day one. Including a number that we're working with, Carson Hydrogen Power Project, the Xcel IGCC High Altitude Project, FutureGen, which we've heard about a little today. There are a number of others that are proposed.

And then in Europe, RWE, Shell in Australia, the Stanwell ZeroGen (phonetic). There are a number of these, some of which you've heard in various lists and various discussions today.

The timeline is an interesting one because everybody asks what and when. And what can you get by 2020. We believe that right now we have to learn from full-scale testing quickly on capture, transport and storage, testing the operability, integration, performance and economics.

The time to permit and design a full-scale facility is about the same time as it might take to permit and design a smaller facility. It might take five years for a full-scale capture facility.

The testing then might take three or four years. Verification, monitoring might be three or four years. And you can add all those together. We hope to see quite a few that are done worldwide, a number in the U.S., possibly some in California, as has been proposed. So we will see large-scale demonstrations and a few pioneering installations. And I should have said the Carson Hydrogen Power Project. I said bp Carson, excuse me on that.

The pioneering post combustion capture, like the AEP demos, will also be done by mid next decade. And then more units might be bought.

If you put this on a time scale with DOE's time scale above, and then some elaboration that we've added to their time scale, if the end game is commercial availability with demonstration, multiple full-scale demonstrations, you're really going to need to have those multiple full-scale demonstrations by the -- before 2015 to make sure that the commercial availability is in by 2020.

That doesn't mean you can't have any installations, but we think this needs to be pushed, and that's what we're trying to do.

Multiple large-scale capture demos. Start today and work parallel paths is our approach.

So what's next? And I was asked to make up five minutes, I hope this does. Is acceleration of industry efforts worldwide. And we've recently had RWE join some of our work in the pilot demonstration of the CO2 capture, as an example. We're looking for others.

New pilots, demonstrations, many initiatives; cost reductions and efficiency improvements in the capture system. And large-scale testing, finding out ways to store CO2 has been discussed before, and will be discussed some more during the course of the day.

Permitting with acceptable risks. And we invite organizations to work with us in this area.

And finally, I'll just mention that this is available, downloadable online for anyone. And we have other information, as well. Thank you.

Be happy to answer questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions. Very good, thanks.

MR. BIRKINSHAW: Now I think we're ready for the next presentation. As you can tell I was so excited that I tried to move him up the agenda. It's truly my pleasure to introduce John Kadyszewski who currently serves as a Coordinator for Winrock International's Ecosystem Services Group and the Director of Winrock's Innovation Program, where he's worked on energy and resource management issues really worldwide for over 30 years.

He has led the development and the application of peer review methods and procedures for measuring terrestrial carbon sequestration in forestry projects, including advanced monitoring tools and combined aerial/digital imagery with spatial information systems to reduce costs.

Under Mr. Kadyszewski's leadership the Ecosystems Services Group of Winrock has developed and implemented monitoring programs covering more than 2 million acres of terrestrial sequestration projects. And has worked to secure sound measuring methods are used in national and international projects intended to reduce greenhouse gas emissions.

Mr. Kadyszewski has worked with Winrock since 1989, and has a degree in engineering from Princeton University.

(Pause.)

MR. KADYSZEWSKI: Thank you very much, Kelly; and thank you for the invitation to talk about terrestrial sequestration.

I'm going to try to cover the topic in some general terms because I think the scale of numbers, it's very important that I differentiate the scale of numbers with a lot of the terrestrial sequestration opportunities, and even the biofuels options, from some of the numbers that have been discussed earlier today that relate to the very large fossil fuel fired plants.

So what I'm going to try to do is talk about the options that are available in California. Connect that up with some biofuels options for California. And then look at the opportunities for geologic sequestration of CO_2 that would be associated with biofuels production.

Just to set it up in context at the beginning. It's important to differentiate between stocks and fluxes. Because these numbers tend to get twisted up when we're talking about biological terrestrial sequestration.

I mean if you look at the atmosphere is 750 gigatons of stocks, the terrestrial vegetation now is about 610 gigatons of stocks. Soils have 1500 gigatons of stocks. So, stocks are fixed amounts.

If we look at the amount of increase in greenhouse gas emissions in the atmosphere since we started tracking it, something on the order of 25 percent of it has come from a reduction in the carbon stock stored in vegetation. That has occurred as a result of changing land cover before station changed uses of land.

And so when we're talking about increasing the carbon stocks in terrestrial vegetation, we're reversing a process that's taken place over the past 100 years that's led to those increased levels in the atmosphere.

Now, looking at the fluxes in any particular year you're going to be taking a certain amount of CO2 out of the atmosphere and putting it into vegetation. And -- well, let me stay here for a second.

You're going to be taking a certain amount of CO_2 out of the atmosphere and putting it into vegetation. That amount of CO_2 removed from the atmosphere is also a potential source for biofuel production. And I'll show you some numbers as we go through that try to capture the magnitude of what this potential impact is.

But if you look at the CO_2 taken out of the atmosphere and put into a biofuel, if you are able to capture some of that CO_2 when the biofuel is burned, and geologically sequester it, you've effectively reduced atmospheric concentrations of CO_2.

So in the short term, the only cost effective option for reversing the accumulation, so I'm not just talking about avoiding increased emissions, I'm talking about reversing the current concentrations in the atmosphere, is to use what nature has used traditionally, and that is plants.

Can these make a difference? And here's where the order of magnitude on numbers comes into play. The current plans for ethanol production, there's two operating facilities in California, and there's another half a dozen planned. Those facilities would produce something on the order of

420 million gallons per year.

Associated with that ethanol production as a byproduct of fermentation is about 800,000 metric tons of CO_2. That CO_2 is available in a relatively pure form and could be geologically sequestered right away. Minor cleanup, removal of some of the trace gases in there.

That 420 million gallons of ethanol that's projected for California is less than half of the ethanol that California currently consumes as part of its transport fleet. And if you look at the number that Larry put up in his slide earlier of 188 million metric tons per year of emissions, this let's say 1 million metric tons of potential geologic sequestration is a small number.

If you were to double and take all of the ethanol that California was producing and sequester it, you might hit the 1 percent level in what could be taken out from existing vehicle emissions.

Another piece of the fuels question. The terrestrial vegetation is taking up CO_2 across the state on a regular basis. And many of the -- much of the growth of vegetation contributes to hazardous fuel loadings in California's forests.

I'm going to put some numbers up later on and show you the basis for the analysis, but just to give you a feeling for the magnitude of this potential impact, if you were to go in and treat 15 percent of the lands at high or very high risk of fire in the state, that would potentially produce on the order of 48 million metric tons of fuel.

And if I was to take that through a syngas Fischer Tropsch plant to produce biofuels from it, I'd have on the order of 1 million metric tons of CO_2 as a byproduct of that available for geologic sequestration. So, again, a very small number in terms of the overall need for the state, but something that could be available in the medium term.

Looking at terrestrial sequestration, itself, in the work that we did with support from the PIER program back starting in 2003 as part of the WESTCARB project, the quantity that looked reasonably available from afforestation in California was on the order of 3 billion metric tons over a 40-year period.

If I look at that as the technical

potential and say, let's say we could achieve 15 percent of that, that might be on the order of 11 million metric tons of CO2 per year over a 40-year period.

So adding up these relatively modest amounts and then trying to multiply them, we might be able, with an aggressive program, to hit a 10 percent of the biofuels targets in the state through terrestrial sequestration linked with biofuels.

So, I wanted to put the big numbers up front in the presentation. Now I'll explain a little bit how we got there. And there's numbers laced throughout here which are helpful if people are trying to do rules of thumb. It's complicated in terms of the levels because there's so many different units that could use on a global basis. Acres and hectares and tons of CO2 versus tons of carbon.

Basically when plants are sequestering carbon it's the difference between the carbon fixed in photosynthesis and the carbon that's respired at night. That's how much goes into the plant.

In here we're looking at this 3.5 to 12

tons of CO_2 per hectare per year as the amount that a given piece of land might be able to take out of the atmosphere. That range is the result of the climate conditions and the water availability and the soil characteristics.

And so when you're looking at very good sites you might get 12; very bad sites you might get 3.5. You're probably going to be somewhere in between.

The numbers across the bottom are the amount that can be potentially sequestered in soils. So plants grow in soils, plants put CO_2 into the root structure belowgruond. That also has a certain uptake rate. And depending upon how you manage your soil, your agricultural practices, you can get between a quarter ton of CO_2 per hectare per year, and as much as 1.8 tons.

When we talk about terrestrial sequestration we divide the biomass that's being sequestered up into pools. And so we talk about carbon pools, there's the carbon that's in the biomass of the trees, the understory and the roots. There's also dead biomass that's laying on the ground, or standing dead biomass. That can be divided into both coarse and fine amounts.

There is the carbon captured in wood that is harvested to make products and goes into long-lived wood products. And then there is a certain amount of carbon that ends up in the soil. And you have to look at all of these different components when you're trying to evaluate progress.

For example, it's very commonly said in the timber industry that the forest will max out in terms of its carbon production and start losing carbon after some period of time; and that'll vary between 60 and, you know, 120 years, depending upon who you're talking to.

In reality when you look at forests and you treat the dead biomass pools, carbon would accumulate for a much longer period of time, but will accumulate in the dead pools.

And so when you go to very old growth forests you find much higher carbon contents that continue to accumulate, even though the amount in the live biomass might have reached a steady state.

To give a rough example of the split, that maroon color is the amount captured in aboveground biomass; it's the dominant portion.

The belowground biomass is the yellowish band. The litter layer is that lavender band.

Looking at FRAP data, California Department of Forestry information on annual emissions and removals by cause from California's forests, interestingly in here the regrowth number for California forests is about 11 million metric tons CO2 per year.

So, again I want to contrast that with if you have 188 million metric tons of transportation emissions, the forests in California on an annual basis are only removing 11 million metric tons of CO2 per year.

So if you were able to capture all of that regrowth and convert it into biofuels and sequester the outputs geologically it would still be a minor impact on the net transport sector.

Interesting other numbers in here, and this surprised us when we did this work, we would have thought that harvest would be the largest cause for forest loss. But, in fact, in California fire is the largest cause of forest loss in the state. And that led us to do some additional research, and I'll present some of those results a little bit later.

Looking at terrestrial carbon sequestration, basically the biggest opportunity is afforestation. And that takes place on rangelands and forests.

Soil work in agricultural lands, California's agriculture is quite different from the rest of the country. In that it changes crops frequently and changes management regimes frequently, and it's very hard to look at a sustained management program that would increase soil carbon over time on that type of agricultural platform.

In terms of the work that we did for California we looked at rangelands and forestlands and we tried to, using spatial modeling and data from the FIA, the Forest Inventory Analysis that the U.S. Government does, and data from California Department of Forestry and FRAP, we looked at particular site characteristics, soil types and tried to project out over 20, 40 and 80 years how much carbon would accumulate if a piece of rangeland was converted into a forest, what it would cost to make that transfer, including both the opportunity cost for the landowner, as well as the costs of the planting and the costs of the initial keeping out the competing weeds and any kind of fire management that was necessary.

And also what it would cost to measure this in a way that would hold up to C-CAR standards.

The largest cost in here obviously is the opportunity costs. What's the opportunity costs mean? That's the cost that represents the alternatives that a landowner might have for using their land.

And so in California, because agricultural land has very high value uses, the biggest opportunity for terrestrial sequestration is on rangelands. And the opportunity costs that have been calculated here have been based on the forage value of the particular piece of land. So we would do an estimate of how much forage a particular piece of land could produce. And then valuing that in terms of traditional agricultural market values.

The primary findings from the work when we looked across all the different options were that afforestation was the largest opportunity. That there are large areas of grazing land in the state that are suitable for afforestation at relatively low prices. Prices under the $10 to $15 a ton CO_2 that have been talked about here today.

There are some opportunities for conservation and changes in management practices to increase carbon stocks in existing forests. But overall that's a relatively modest opportunity. There has not been a lot of deforestation going on in California.

One of the things we were asked to look at was the impact of development on forest cover. And whereas development has broken up a lot of forests into smaller landholdings, for the most part trees have stayed on those smaller parcels because they add value to the landowners' land.

Now, over time there is a question of whether that changed management practice will lead to healthy sustainable forests. But in the short term it has not led to a lot of emissions associated with development.

And therefore, it's hard to make a case for conservation in many parts where, in fact, it's very difficult now to convert land out of forests. There still are, that being said, many places in the state where there are understocked forests. Where forests have been over-exploited, and where changing management practices to maximize carbon accumulation will lead to a increase in the carbon stocks on those existing forestlands. And a benefit from conservation.

On fire, that was sort of our surprise finding. We think that there are opportunities for increasing carbon sequestration by changing fire management practices. And I'm going to show you more information about that shortly, but that requires methodologies to be developed. Because there isn't any place in the world that has been doing that so far.

And it's a challenge because you have to prove a counter case. You have to say, well, what emissions would have occurred in the absence of better fire management. You have to presume a certain rate of fire and a certain area burned and a certain amount of emissions with each fire in order to say what would be saved.

Afforestation case. We're really talking about taking these kinds of grazing lands and putting trees on them. There has been concerns expressed about water requirements. Many people have said that the water situation has changed so dramatically. But in the detailed analysis we've done we have not really found that to be the case. Although probably that is worthy of additional research.

Looking at the accumulation rates for particular trees, that black line you see in the upper left-hand corner is redwoods. They certainly are some of the fastest growing trees, in addition to being the trees that will accumulate the most carbon.

When you go down to the hardwood forests, that top line is really riparian hardwoods that produce the most rapid growth rates.

This gives sort of a summary table of the amount that's possible. If I draw your attention down to the sort of, this is a busy graph, I understand, but at the 40-year point, at under $13.60 a ton CO2 you have about 3.2 billion metric tons of potential across the state on grazing lands. If you stretch that out to an 80-year timeframe, you might get up to 5.6 We're talking here about 17 million acres of potential land that would be converted at those price points.

Part of the reason for the awkward numbers is these were initially all done based on a price per ton carbon. And so that's equivalent to $50 a ton carbon. It's $13.60 a ton CO2; and $2.70 is equivalent to $10 a ton carbon.

But you can see when you drop that price down to 2.70 you still have 1.6 billion tons of opportunity in the state.

So when I threw a number up earlier saying 11 million metric tons per year if we got 15 percent penetration, that is very conservative when you look here at the alternative at a very low price. That would represent more like 30 million tons per year over that initial 40-year period of time.

Just a quick comment on conservation. This is maybe just for California because contrary to popular belief the tropical forests do not have the largest carbon concentrations per hectare. California's forests do have the largest sequestration per unit area on the planet in the redwood forests, topping out at the 730 tons CO2 per acre.

The sierra mix conifers, the old growth, 150-year-old forest, for that type of forest are also up there at 575 tons CO_2. And so these forests really are the best carbon accumulators on the planet with the largest carbon stocks. Conservation of those kinds of forests -- I mean to cut down an acre of that kind of forest is a big emission.

I'd just like to put that picture up because those are trees -- a lot of discussion about, when we talk about afforestation in California people forget the size of the forests in California, and the amount of carbon that was caught up.

And looking at management practices you don't have to -- in fact, your forest industry might help you in managing forests over time. You don't have to not have harvesting in order to have healthy renewal of these forestlands.

Now, fires. Between 1990 and 2004 about 5.5 million acres of area burned. That's not all forest area, that's the area burned. And so the estimate is that about 26 million metric tons of CO_2 emissions occurred as a result of those fires, plus some amount of other greenhouse gases from the smoldering nature of those fires.

The Air Resources Board has a set of

indicators that they use for different kinds of fires to predict what those emissions profiles are. But over time, 26 million metric tons is not a very large number.

And so one of the challenges in looking at fires is do you believe that as the data suggests, that fires are an increasingly frequent occurrence in California. And therefore, do you set your baseline as you're avoiding the larger rate of fires in the future, or do you just rely on historical information.

And so currently we're working with a panel of different fire experts and fire modelers and climate modelers to try to come up with the consensus across different scientific disciplines for methodologies that could be used for predicting benefits from fire.

The biggest thing that you're trying to do really is you're trying to reduce the incidence of uncharacteristically severe wildfires that lead to larger-than-normal emissions. Fire is a normal part of the environment in many of California's forests. And so what you're trying to do is reduce the losses from the large trees, which under normal conditions would not burn during a fire.

But when you allow hazardous fuels to build up over many years, the fires get hotter; they burn hotter longer; they kill the large trees; they burn the duff layer off. They can vaporize some of the micronutrients in the soil and that leads to a change in the ecological characteristics of that piece of land in the future.

So, you're trying to shift away from that kind of fire back to a more normal fire regime. By doing that you're also maintaining your carbon accumulation rates.

When fire burns through a forest and doesn't kill the trees, the trees continue growing. The root structure is there. They continue growing the next year at the same rate they were before.

If you kill those trees you have to have new trees coming in; and there's several years before they reach canopy closure and can start up again.

The smoldering kinds of fires, you get different greenhouse gas emissions. And so by managing your forests differently you can control the split on those emissions. And data suggests that that will lead to a net decrease in the CO_2 equivalent gases.

And then also, if you're able to take these fuels out of the forest, and rather than let them burn in this way, convert them into some kind of a biofuel you can use that to offset fossil fuel emissions.

Not all fires are the same. So looking at, this is a thinned forest. And when a fire burns through a thinned forest it goes in a line. It does not get up into the canopy. That's why you'll have some emissions, but you'll have live trees.

Whereas in an overgrown forest that is densely packed, when you have a fire it gets into the crown, and that's where you have an uncharacteristically severe wildfire with much higher associated emissions.

Looking at a statewide analysis, and this is using CDF and FRAP data, and you look at the cause for canopy change in different parts of the state, fire is the major cause for canopy change in the state. So in the northern Sierra District, that particular region, 47 percent of the canopy cover change is as a result of fire.

This gives you an example of -- this is sort of a land use cover map. I'm going to point out a couple of areas. This area over here is the 1978 Whitmore fire. Here's a 1988 fire. When you look at these fire perimeters what you -- this is where we first looked at ecosystem-changing fires.

The green area is classified as a forest. This yellow area is now classified as non-woody riparian. That means it has not recovered. This is a 1978 fire and 2002 imagery. So the idea that when fires go through, the forest just comes back, is not the case.

And when you do fire perimeters like we have here you can trace back and find historically where many of the worst fires have been. You do not get regrowth within these 30- and 40-year time periods.

What happens to carbon stocks in a fire? You know, some part of them go on and live; but there's a percentage that is volatilized and lost. that's what you're trying to effect. You're still going to have soot and charcoal and dead wood that remains in the system.

You saw this map earlier. Larry put up

the geologic sequestration opportunities adjacent to the forestlands. That green layer was the forest in California. The red layer that's on top now are mixed conifer and ponderosa pine forests that are at high or very high risk of fire. That is where most of your fire loss occurs in the place where you'd want to concentrate on fire management activities.

They do happen to be adjacent to the Central Valley. And so if you were going to locate biofuels facility based on taking out some of this hazardous fuel load from these endangered forests, you could do it on that boundary next to those geologic sequestration sites.

When we looked at this in terms of quantifying it, 16.2 million acres at high or very high risk of fire. That's those red zones. If those were to burn, this is looking at the fuel loads, this is not the average that we were looking at before, this is our projected amount of emissions associated with those particular lands based on their hazardous fuel loadings.

And so you'll see there's a higher number in there that we would expect to burn; that 80 to 185 tons of CO_2 per hectare.

Right now only about 2.2 million acres of that could be treated if you were going to take it to a biofuels plant. And that's because there's not biofuels plants close to all the places where you have hazardous fuels.

But we did some mapping here to look at those places that were within 50 miles of a biofuels facility, that were on slopes that were accessible, that were close enough to a road that you could extract those biofuels, and that were of a sufficient block size that you could afford the transaction costs of mobilizing equipment to get in there and treat the land.

And it came out that about 2.2 million acres of that land right now could be treated; and have that brought out into a biofuel supply. So, 2.2 million acres at 80 tons CO_2 per acre, you could look at siting plants at other locations besides that.

What you're trying to do looking at carbon markets to say whether or not the value of this carbon benefit is sufficient to improve the management, the hazardous fuels management in California forests.

So what you want to do is find the

highest and best use for any of that material you're going to take out of the forest to reduce fire risk. Some of it might be small dimensional timber that goes into the product mix. But there will be a percentage of it which will have no other value than a biofuel value.

And then you want to try, if you were going to go after this fire-loading biofuel opportunity, you'd want to be shifting resources away from fire suppression towards fire prevention. And then you want to provide incentives for landowners and the forest products industry to take that fuel out and convert it to biofuels rather than allowing it to burn as nature gets around to burning it.

I have been talking about terrestrial sequestration; spent a lot of time on the four issues that have dominated the international debates on this. Baseline, we've talked a little bit about that with the fire case. You have to have what would you assume to be the situation. What would happen in the absence of your fire project.

Or afforestation; what would happen if you just left the land abandoned. Would trees grow back naturally. So we've talked about baselines a little bit.

The permanence question, we've heard about geologic time, that permanence, meaning thousands of years. People have criticized terrestrial sequestration projects as being impermanent. And especially with climate change. The threat to these kinds of vegetation types as climate changes will be greater. But permanence, in fact, if you look on a planetary basis, there has been a storage of carbon stocks. And so it's a question of how you regulate and manage that permanence feature.

The additionality question, is it additional. Would someone have done it anyway. That's a very tricky question and we don't have time to discuss it here. Leakage, if you're looking at changing practices on land, such as conservation, we're not going to cut these trees. Does that mean that people will just cut trees someplace else.

Or if there's a certain demand for timber, just because they don't cut it here doesn't mean they won't cut it someplace. And so conservation projects have been questioned on a leakage basis. If you don't have boundaries around your entire area, they can be challenged.

Shifting over to the biofuels options. Now that we have options for increasing terrestrial sequestration, and we have potential sources of biomass that could be converted to fuels or electricity, what do those options look like.

So there's three pathways that are talked about the most. There's the lipid or oliochemical pathways. This is mostly vegetable oils, animal fats going to biodiesel. There aren't a lot of associated CO2 in the processing facilities with these plants.

There are some interesting things coming down the road. I mean, at this point in time vegetable oils are not particularly competitive. It's a food-versus-fuel question. And when there's pressure on markets the price for the vegetable oils, even at $65 a barrel gasoline, hasn't been able to compete very well. There's new things coming in this area with algas and higher biofuel-per-acre kinds of production levels. But I'm not going to talk very much about that particular pathway in the context of geologic sequestration.

The other two opportunities, however, have geologic sequestration potential. Some immediately and others in the medium term. And so clearly the one that is the most immediate geologic sequestration opportunity is the CO2 associated with ethanol fermentation. When you ferment sugars to make alcohol you produce CO2.

Cellulosic processes are still fermentation process. So even when people say we're going to do new second-generation biofuels, ethanol production, it's still a fermentation process. It still has associated CO2.

The thermochemical pathway I'll talk about also. That is the syngas pathway. That's very similar to what's been talked about earlier with coal where you're going to gasify biomass into syngas. Then you can run it over a catalyst bed and produce a biofuel.

The difference from coal is the CO2 in the plants is coming out of the atmosphere. And so when you put in your transport fuel and burn it in your car, it's a net zero, aside from whatever you may use to produce it.

The potential benefit comes at the

processing plant, because when you're making the fuel from the biomass you are -- a certain part of the carbon is used to make the fuel. That's the part that can be separated, captured and sequestered.

So when I'm talking about ethanol fermentation, for example, about 15 percent of the carbon that goes into the ethanol plant comes out of the ethanol plant as CO_2. The other 85 percent, some of it is burned and emitted right away; and the rest of it is in the fuel which is later burned in the car. So that 15 percent is the part that is immediately available for geologic sequestration today.

When you go to the thermochemical pathways, the thermochemical pathways, depending on your assumed process, but if you go to a oxygen-fired gasifier high-efficiency system, you're probably going to have available something ont he order of 40 percent of the carbon that could be sequestered geologically at the back end of that plant.

I won't spend a lot of time here. The liquid fuel process is obviously either fermentation, thermochemical. You've heard a lot earlier today about oxyfuel combustion and gasification. Biofuels can be co-fired with coal. And so some of the net zero coal plants have looked at coal firing a very small percentage of biomass. We've done quite a bit of work on that in the southeastern part of the United States. We haven't done much on that in California because we haven't seen coal as a big part of California's future.

Looking at the ethanol plants, themselves, the two operating plants in the state, 25 million gallons and 35 million gallons at Goshen and Madera. There's five additional plants under development that are going to add 340 million gallons per year. BlueFire has one of the cellulosic plants from wastes. A plant with 24 million gallons per year in Corona.

But putting all these together is the number I showed you upfront. That's 424 million gallons per year, once all these plants are completed, with an associated 800,000 metric tons of CO_2 per year that could be geologically sequestered.

What normally happens to that CO_2, we heard mentioned in the prior presentation that there is a merchant market for CO_2. Can be used for different purposes.

But before I go to that, here is the location. You'll notice that this nice green Central Valley region is the basin that was in the middle of Larry's map of good places. But if you go and look at all of the existing ethanol facilities, they're all located, or planned to be located, very close to what are good basins.

And whereas we're talking about at that scale, things that are less than a million tons per year, it's still a measurable activity that at this point in time there are very little additional incremental costs involved.

The CO_2 gas, 99 percent by volume of the gas coming off ethanol fermentation is CO_2. There are some trace gases. You do need to do a little bit of filtering before you want to put this belowground.

A little bit about the market. Currently on a global scale, mentioned flash-freezing of chickens or vegetables. The current merchant market for CO_2 globally is about 20 million tons a year. U.S. consumption is about 8 million tons per year. This is not including anything that's being done currently for enhanced oil recovery. This is just the market that's principally going into beverages, baking soda and flash-freezing operations.

That CO2 associated with ethanol passed 11.5 million tons in 2005. So, you can see that the ethanol business alone is now producing 25 percent more -- actually 33 percent more CO2 than the total consumption in the U.S. That will change some of the market applications because there'll be a surplus.

But the rapid growth in ethanol expansion has not yet been absorbed in the CO2 market, and we see a lot of business plans being put together that are assuming a future price for CO2 that doesn't exist in the absence of some kind of climate change benefits, because there's not enough demand.

California probably will not see that in the short term because in the prior slide you notice this is all the ethanol plants concentration. So that's where CO2 can't find anyplace to go. Out here you have a much smaller number, so you might not see that problem as soon as other people will.

But the prices in the merchant market range from \$30 a ton to \$120 a ton. I see the \$140 and the \$200-a-ton food-grade materials, but that's really very very limited markets. And usually in places that are forced to do it for some other reason.

We'll see raw gas sales; in other words, some of the plants that are now being built are willing to sell their CO2 for as little as \$10 a ton, untreated. You'll take it as it is; you have to then treat it a little bit to get it in the ground.

On thermochemical side, you've heard the description of the gasification processes. You can use IGCC with biomass just as well as you can with coal. A little more complicated. Biomass has different properties.

We worked with Potlatch Pulp and Paper Corporation to put together a feasibility study for a plant that they were going to build in Cyprus Bend, Arkansas, aimed at 800 tons a day. This is about a \$750,000 study. It was part of agenda 2020, which is the pulp and paper industry's research arms; investigation of what things they might do in the climate change arena.

And so I feel fairly good about the, at least the conservative nature of the numbers that are in this report. The 1800 tons per day, our estimate, looking at a plant that could be built commercially today, is in the 50 to 55 gallons per dry ton is what your yield would be. Associated with the 1800-ton-per-day plant would be about 250,000 tons of CO2 per year.

Just a schematic of the plant. This particular plant, the economics depend on the waste heat being sold to the pulp mill. So if you just wanted to do this as a straight fuel production plant, it would not pencil out. But because they are co-located, and so really it's a cogeneration facility and 70 percent of their energy is being sold. the combination of the revenues from the heat with the revenues from the fuels makes it into an attractive financial investment.

You know, just in general on biofuels, on a national basis there is around 6500 megawatts of installed capacity. The power prices tend to be high. So if you look at your fuel as being free on site, which is what most of these plants have, waste disposal situations, you're talking about 5 cents a kilowatt hour to build a conventional kind of biofuel system.

When you put $40-a-ton fuel cost on it, you're up to 9 cents. And each $10 you add to that ton of fuel price is going to add a penny a kilowatt hour.

Looking at the bioenergy plan that was done for California, the analysis showed about 30 million dry tons available fuel, of which only about 4 million tons is now being used. About half of this is forestry-based fuel.

When you go to the power side of the equation, the IGCC processes developed for coal can be used for biomass, as well. There'll be some disadvantages because you can't afford to transport biomass the long distances that you can coal. It has a lower energy density, so it does not lend itself to the very very large scale plants. Some disadvantages.

But you can use oxygen blown combustion there also. Again, you have the oxygen cost problem and the penalties you pay for trying to run small oxygen plants at small facilities. But in general, we don't see IGCC biomass prototypes available in the next couple of years. But we do see them as being available in the medium term as the coal technology matures.

I throw this in just as an indicator because one of the things when you look at terrestrial sequestration and fire management and biofuel markets, it's important to know the values associated with the additional biofuel you can collect if you have extra money available.

And so if you have an extra $10 a ton, so let's say in order to take the hazardous fuel out of a forest you have to pay $50 a ton. Each $10 you ratchet up is going to add a penny a kilowatt hour to your power price, or 10 cents a gallon to your fuel price.

And so if you say we can tolerate $3.20 a gallon gasoline, for $3.30 you can pay an extra $10, and you can collect that much more fuel.

So when you're trying to integrate your planning for things like hazardous fuels management with a biofuel production strategy, just rule-of-thumb numbers.

If you go to the more efficient IGCC type of heat rates for bio power plants, and here I'm using an 11,000 Btu per kilowatt hour heat rate, it's based on one particular study. If you go to an 80 megawatt plant running at an 80 percent capacity factor, which is low, but not so low for a biomass plant, you're talking about 565,000 metric tons per year.

So if I take that up to 15, let's say we're going to use the 50 percent of the forest slash that's available in California, I'd be multiplying that number by 30 to get you a megawatt number for what the state could potentially produce.

When you combine this with the terrestrial sequestration benefits, you can go in and look at some of the afforestation work that's being done in regions around these kinds of plants.

Running to my conclusions, the opportunity for terrestrial sequestration is more than 3 billion tons over the next 40 years. That's the largest single opportunity; and it's the largest by far. There's nothing else that's even close to that.

California can reduce its CO2 emissions, and I estimate you probably could hit 10 percent of your 188 million metric tons of transportation emissions by a concerted effort to focus on these kinds of opportunities with the right incentives and regulations.

You could be looking at capture and storage tests immediately now with ethanol plants. Probably could find willing partners with them; they'd want to be paid something for their CO2. But that would work into the overall package. It does not have a lot of additional capital expenditures required. And with the proper kinds of -- and there already are policies in place that set targets over the next several years for a percentage of power produced with renewables, and a percentage of biofuels produced in the state that are going to provide some economic incentives to people who want to locate facilities here. And some additional thought might be able to encourage some of those facilities to look at carbon capture and storage association.

Across the course of this presentation I cited data from a bunch of different pieces of work that we've done out here. We worked very closely with EPRI in the early years on some of this analysis. And the PIER program has supported a lot of the work in the state.

California Department of Forestry has

helped us with some small things, and looking at particular forest management options.

Thank you. Questions.

PRESIDING MEMBER PFANNENSTIEL: Very good. Thank you a lot. Questions?

COMMISSIONER BOYD: I don't really have a question. I just want to add my compliments to you, John, this is a topic that some of us have been working on for a long long time. You put a lot of really good data out there that will continue to help us in what's become a crusade almost. Nonetheless, thank you for the presentation.

PRESIDING MEMBER PFANNENSTIEL: It's going to take us awhile to digest it all, but thanks very much.

Kelly.

(Pause.)

MR. BIRKINSHAW: Okay. Now I get to wear my other hat this afternoon. I'd like to talk to you -- Kelly Birkinshaw, for the record. I, as I mentioned earlier, manage environmental research for the Energy Commission.

I'm going to be talking about some complementary work that we're doing here in the

Energy Commission. Was really mandated by recent legislation by Assemblymember Sam Blakeslee in 1925. AB-1925 has mandated that we work with the Department of Conservation to broadly look at virtually all aspects of carbon sequestration, geologic carbon sequestration in particular. To accelerate and develop a commercial carbon sequestration market here in California.

This work that we're doing, I think, really complements the technology oriented research that has historically been the foundation of work here in the Energy Commission.

As I mentioned, the legislation, which was passed in August of last year, mandates that we work with the Department of Conservation. And it really is focused on accelerating the adoption of geologic sequestration here in the state.

It's a report that we have to produce and submit to the Legislature November 1st of 2007. And is to be included in the 2007 Integrated Energy Policy Report.

The next three slides, I think, are more introductory and much of this material has been covered in earlier presentations, so I'll go relatively quickly. Although I would like to make a couple of points along the way.

This particular graph shows scenarios of carbon emissions over time. The first being what would happen if we maintain use of existing technology. The second middle graph line is emissions were we to worldwide adopt a fairly aggressive carbon reduction strategy.

And I think one of the things that's pretty illuminating is the list of technologies that are assumed in that top wedge. We're really talking about advanced and emerging energy efficiency technologies, renewables and a very broad adoption of nuclear energy.

And yet we still have a gap. The bottom line is the carbon budget that we would have to adopt if we're to stay below the 450 parts per million threshold that was talked about this morning. And hence, the opportunity for technologies such as carbon sequestration. This, I think, just further emphasizes the point that there really is no silver bullet.

Others have shown variations of this cartoon. It just simply illustrates the geologic carbon sequestration. The only thing I'd point out is that coal seems really is not an option here in California. But, as mentioned earlier, we do have considerable potential in oil and gas fields, as well as really potential in saline formations.

Larry Myer, I think, talked about the work in WESTCARB and phase one, examining where the potential was in the United States. And particularly profound potential here in California for geologic sequestration. I think one of the points that I'd like to make, though, is what's been done to date is really just the first order of analysis. Any particular site would require considerable additional study to determine if it was a candidate for geologic sequestration.

And I think that's really one of the focus of the legislation Assemblymember Blakeslee passed. And I think in that regard, his legislation was really quite technically astute in asking the right questions that need to be addressed beyond just developing technology.

In this slide, what we've tried to do is to put the topics, if you will, of our report in the context of the major steps in developing a commercial project.

And you'll see here that beyond a broad

review of the technology, both in terms of capture, as well as storage, will be examining questions of economics, and getting into some of the major issues associated with creating a legal and regulatory framework for sequestration.

In particular, examining site certification and the elements of site certification protocol. We need to examine integrity and longevity standards for reservoirs. A major element of that would be assessment of risk. Examining what options are available to quantify risk at a particular site.

We'll also be addressing questions of remediation in the event of leakage. And I think a key part of the report will be an examination of indemnification and liability issues.

In much of this we have analogs, particularly from the oil and gas industry, we can look to in examining what the options are and how well they might work in sequestration.

We have to -- well, put it this way. I think that one of the objectives of the legislation was to insure a strong scientific foundation for, you know, any future law or regulations governing sequestration.

And what we've found, unfortunately, is that the timing did not quite align with the ongoing research in California, particularly that of what's going on in our phase two WESTCARB program, or phase three.

As a result we've had some discussions with the author, Assemblymember Blakeslee, and are moving now on a trajectory to do a two-phased approach in which we will produce reports this November that provides a state of knowledge as we understand it today; but frankly, in many cases, will just tee up some important questions that need to be addressed through research.

And then a re-examination or more of a final report that would be due in 2010. And hopefully by that time we'll have the ability to rely upon data and analysis that have come out of some small- and hopefully large-scale demonstrations of carbon sequestration. And can more comprehensively address some of the key questions posed by AB-1925.

We have worked out in considerable detail with our colleagues at Department of Conservation the elements of producing this report. This has been fairly straightforward actually because the Department of Conservation has been a key stakeholder and partner from the very beginnings of the WESTCARB, beginning in phase one.

And, in fact, the California geologic survey received some funding to do some of the broad geologic assessment that is part of the phase one program. The geologic survey will be continuing their survey work. And it will be updating the maps, looking at both the technical potential here in California and the staff at the Division of Oil, Gas and Geothermal will be working with us and other experts that have been retained to insure we broadly capture the regulatory issues that need to be addressed fairly comprehensively in the report.

We at the Energy Commission have the responsibility of pulling this whole program together and integrating the input from the experts retained, as well as input from other key stakeholders in this report. And then synthesizing it into a form that can be put into some section of the 2007 IEPR.

I think it's important to note that we are working very hard to reach out to all stakeholders that might have an interest in this topic. There are a number of government entities that have expressed an interest and will be providing guidance to us, both on the scope of the report, as well as methodology.

And, of course, providing review of the papers and of the final report, including the Air Resources Board, who is very interested in integrating what we learn from this into their assessment of strategies for AB-32. As well as EPA Region IX.

A number of other both industry stakeholders, as well as NGOs, have also expressed interest and are included in this project, again, in a review mode.

As I had mentioned earlier, a key part of this is augmenting what's already been going on in the research that's been done through the WESTCARB, through experts that have been retained to examine some of these legal and regulatory issues. And then integrating that into a single assessment.

This is my final slide. Just provides some milestones, as well as key dates. I guess the one I'd like to focus on is we have retained the experts that will be doing these whitepapers. And we will be having a workshop at the Department of Conservation on June the 28th.

This would be a staff scoping workshop; an opportunity hopefully for a fairly informal conversation about the key elements of the report; the methodologies and data sets that will be foundational to the analysis. And an opportunity for stakeholders to comment on both the scope, as well as the methods that we're using to reach conclusions.

We also are planning a public workshop; this would be, we would imagine, a Committee workshop, October. I think I was told just before this presentation, October 1. Open to the Committee. And then again the report, itself, must be submitted by November the 1st.

So that really concludes my presentation. And I'd be happy to answer any questions. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Kelly. Questions?

I think we will turn to public comment. We've had some really valuable presentations. I have one blue card from somebody who has asked to speak. Leonard Devanna.

MR. DEVANNA: Thank you for the opportunity to speak, and I will make it brief as I recognize the day is getting long for everybody.

I'd like to make some comments that mostly focus on this morning's session. And from that session I heard at least two conclusions, and I'm going to add an editorial piece to it, myself.

I think the morning started off with kind of a warning that the climate is warming and that we need to take immediate action. The second piece that I heard was that the big coal solution is going to take time and major government funding before it is commercially available.

And I guess as an editorial comment I would add it would probably not be any consensus of an energy strategy to pursue while we're waiting for a coal solution, for another solution, perhaps except renewable energy. And we would probably all agree that there's not sufficient renewable energy to meet what we would like.

That leaves us with a sense of urgency of kind of the status quo. And I don't think that was the intention of what -- that that's the intent of what you're looking for.

I want to express to the Commission that there are other places to look for the solutions that compliment today's presentations. Rather than only relying on the big box solutions, the CEC and the State of California should also be implementing the policies and regulations that encourage innovation and signal to existing new companies that there is a California electric power market for fossil fuel power having zero or near-zero emissions.

Today there are emerging solutions out there in addition to FutureGen and other large industry research initiatives. We at Clean Energy Systems are one of the solutions, and have projects emerging in Norway, the Netherlands, Canada and the Middle East involving the generation of zero emissions power. We also have a 50 megawatt project announced in California.

However, there is a major obstacle that we and other emerging technologies face. while the California utilities have been very supportive of our company, including Southern California Gas Company investing several million dollars in our technology, the power that the California utilities purchase is largely dependent on the instruction and biases that they get from the CEC and the CPUC.

Together you have been very effective in having the California utilities create, perhaps, the biggest market in the world for renewable energy. By creating this market you have contributed to the development of renewable energy technologies that benefit California and the world.

Our problem is that the CEC and CPUC have not given the same signals to the California utilities that will create a market for technologies that will reduce the emissions from the combustion of fossil fuels.

Let me give you an example. With our technology we can generate zero emissions power for 8.5 to 9 cents a kilowatt hour. A high price, but certainly competitive with renewable energy.

In discussion with various turbine manufacturers they generally agree that there is a second-generation turbine available that can be developed with existing technology that would lower that cost of power to about 6.5 cents, and still achieve zero emissions.

However, the turbine manufacturers and

others consistently ask us one question. Where is the market for zero emissions or near zero emissions power. When we point to California they respond that California is totally focused on renewable energy, and that there has been no signal otherwise out of the CEC or CPUC.

When we point to the 1100 pound CO2 per kilowatt hour CO2 emission standard, they say they simply endorse current state of the art and gave no signal they wanted an effort directed toward newer technologies.

My request to you is that in cooperation with the CPUC you develop a program that creates the same incentives for zero or near zero emission fossil fuel power as you created for renewable energy. California is the biggest cohesive market for power in the world. And with this action you would encourage entrepreneurs, equipment manufacturers and others to develop necessary technologies for California and the world.

In closing I'd like to thank you, and particularly thank you for the support that you have given to our company through your PIER program. If it were not for the California Energy Commission and your PIER program, very likely that the technology that we're now bringing to the marketplace may not be available today.

Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you. I have no other blue cards. Perhaps you should bring it up. Go ahead. Just go ahead, and you can just go to the microphone.

MR. KOSTRZEWA: Thank you; I'm Larry Kostrzewa from the Carson Hydrogen Power, LLC. I'm just commenting with regard to the last presentation. We were looking forward to, with great anticipation, the results of the AB-1925 report that the Energy Commission was called upon to prepare.

And that, of course, factors into our own project. And with the report now really deferred to 2010 and not clearly including the recommendations that were called for, that leaves us kind of off on our own, kind of figuring out what the regulatory landscape is going to be for CCS.

So if there was any way to step up that schedule, it would certainly help.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other -- do we have somebody on the phone or on the Webex?

MR. SOINSKI: We can un-mute them to see if anyone has -- they're un-muted.

PRESIDING MEMBER PFANNENSTIEL: Is there anybody on the phone or on the Webex who would like to address the subject?

Don't hear anybody. Thank you, all. The presenters were absolutely excellent today. They have given us a lot of useful valuable information as we put our policy recommendations together.

I thank all of you for being here and for your interest in the subject. And for being part of our discussion.

We'll be adjourned.

(Whereupon, at 4:15 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of June, 2007.