STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Preparation of the 2009 Integrated	)
Energy Policy Report	) Docket No.
	) 09-IEP-1E
Present and Future Central Station	)
Renewable Energy Facility Plant Costs	)
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, APRIL 16, 2009

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ORIGINAL

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Peter Petty
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COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member

ADVISORS PRESENT

Laurie tenHope

Kristy Chew

STAFF and CONSULTANTS PRESENT

Suzanne Korosec

Al Alvarado

Joel Klein

Gerald Braun

John Hingtgen

Kevin Sullivan
Charles M. O'Donnell
Pete Baumstark
Frans van Aart (via teleconference)
Karl-Heinz Lochner (via teleconference)
KEMA, Inc.

ALSO PRESENT

Shan Blattacharya
TRC Solutions

David Townley
Infinia Corp.

John Shears
Center for Energy Efficiency and Renewable Technologies

Matt Campbell
SunPower Corporation

Jenifer Hedrick
Southern California Edison Company

I N D E X

P R O C E E D I N G S

9:02 a.m.

MS. KOROSEC: I'm Suzanne Korosec; I lead the Energy Commission's Integrated Energy Policy Report unit. And welcome to today's staff workshop on present and future costs of central station renewable facilities.

This workshop is being conducted under the direction of the Integrated Energy Policy Report Committee.

Just a few housekeeping items before we get started. Restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs under the white awning. And if there's an emergency for any reason, and we need to evacuate the building, please follow the staff out the door to the park across the street and wait there for an all-clear signal.

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

The workshop is also being webcast;

access to the webcast is also available on our website.

To give just a little context for today's workshop, the Energy Commission is required to prepare an Integrated Energy Policy Report every two years that provides an overview of major energy trends and issues that are facing the state.

The 2007 IEPR identified the need for better data in the Energy Commission's cost of generation model about the costs of renewable technologies, as well as how generation costs evolve. And recommended that the 2009 IEPR focus on developing a process to regularly update these changing technology costs over time.

Today's workshop will feed into that effort by discussing feasible renewable technologies that are likely to be deployed over the next 20 years; cost drivers and trends for those technologies, and the likely cost trajectories.

We'll also be examining two nonrenewable technologies, nuclear and integrated gasification combined cycle.

The information from this workshop is

going to feed into a follow-up workshop on July 22nd on updates to the cost of generation model.

So with that brief introduction I'll turn it over to Commissioner Byron for opening comments.

PRESIDING MEMBER BYRON: Good morning, thank you, Ms. Korosec. Good morning; I'm Jeff Byron. I chair the Integrated Energy Policy Report Committee, along with Commissioner Boyd, who I hope, although we're not certain, but I hope will be joining us. Along with me here at the dais is my Senior Advisor, Laurie tenHope.

And I'm very interested in this subject as it feeds into our IEPR process. When I was in private consulting I'd kill for this information. And here I get to sit and take it all in like a schoolboy. I'm really looking forward to it.

I would also like to let everyone know that this is really what we look to our staff to do, is manage the consultants and the expertise that bring us information and provide the objective reporting around topics such as this.

So, I'm here to learn today, to craft recommendations that hopefully you'll find one day in our Integrated Energy Policy Report towards the end of this year. And I understand, as Suzanne said, that we'll be visiting this subject again on July 22nd.

So thank you very much. I'll turn it back over to staff.

MS. KOROSEC: All right. We'll begin with Al Alvarado who will be talking about the cost of generation model and the project.

MR. ALVARADO: Good morning. I'm Al Alvarado; I'm the manager of the electricity analysis office. We are one group of staff that's working with other program folks within the Commission. We're working really closely with the PIER Staff and the consultants that have been hired to also help us in this project.

I'm here today to just give a general introduction of the cost of generation project, since the topic of today's workshop is just one phase of the overall project.

To provide context of levelized cost of generation project, as Commissioner Byron indicated, you know, this is in support of the development of the 2009 Integrated Energy Policy Report. The cost of different generation technologies is basically a fundamental building block for doing any kind of analysis of evaluating potential generation sources for California, as well as these costs also tend to serve as a benchmark when we estimate wholesale electricity costs, which is also used to evaluate other programs such as efficiency, energy efficiency programs.

We have conducted similar studies in the 2003 and 2007 Integrated Energy Policy Reports. And each cycle we've improved the scope of analysis.

For example, in the last cycle we did develop an easy-to-use and transparent model to calculate the levelized costs of different generation technologies. This is a public domain model for others to use, and we've actually had quite a few requests this past year for this tool.

As I indicated, this is one of the building blocks of electricity resource planning studies. I think this will be applied in a number of different manners throughout other Energy Commission studies.

This is the first phase of the overall project. The other tasks are to modify the levelized cost of generation model that we developed last cycle. We would like to -- we're considering the differences of a cash flow model versus a revenue flow type model. We've also evaluated, looked at other tools to see how our tool compares with others.

An important phase is updating the engineering and financial model inputs. The topic of today's workshop is to focus on the renewables, IGCC and nuclear generation. We have another effort underway to look at the attributes for natural gas-fired generation, which will come in at a later phase of the project.

Key to understanding any levelized cost for different technologies, we really need to understand how the individual factors may change over time. You know, in the last cycle we were able to derive some levelized cost estimates for new generation technologies that would be built today.

In this cycle of the IEPR we are going to consider what are the factors and how they may change in the future to come up with some range of estimates for future levelized costs.

But like everything else, each input to the tool does have its own role of uncertainty, so we want to drill a little bit deeper to better understand all the factors that may actually swing these individual factors one way or the other.

For example, the cost of materials that go into building any of these facilities definitely has changed over time. And we'd like to examine how things may change in the future.

Once we analyze a lot of these different input variables, factors, we will then calculate a range of current and future costs. And in this effort we are also comparing the different levelized cost models.

For example, there's tools that are used at the Public Utilities Commission to identify the market price referent. There's another tool that is used for the RETI that's also coming up with different costs of levelized cost to the renewable technologies. And we have found some differences, so we will be able to get into what those differences are, and get a better understanding about what the implications are.

I don't expect you to be able to read the details in this chart. It's just really more to illustrate all the different factors that we are considering in this project.

I mean there are so many different variables that we need to consider. And each of those variables could shift up and down as we expand the scope of our analysis.

So, on the left-hand of the chart we do provide a lot of input, the plant characteristics we want to consider, the financial assumptions and even some of the general assumptions trying to understand, you know, the differences whether a developer is going to be an investor-owned utilities, municipal utility or a merchant developer.

The outputs we will identify the levelized fixed costs, variable costs, the total levelized costs. As another one of the outputs we also will be able to derive screening curves, and this will give us a better chance of comparing one generation technology next to the other.

The goals of this project has, and still is, to, one, develop a transparent, easy-to-use tool that most folks can use for deriving levelized costs of different generation technologies.

But to do so, we think it's really important to consider a consistent set of financial and operation assumptions that would apply to all the different generation technologies. This way it would give us a better handle in terms of if we want to compare one technology next to the other.

We found that in some studies some of the input assumptions were just so far apart. And, of course, that gives us very different results in the calculating of levelized costs.

We do want to understand the, as I indicated earlier, the different variables and scope of uncertainty, just to derive this range, rather than one single-point cost estimate.

Just to sort of emphasize the point, this is a slide that we used for the 2008 update report. And we've had staff go through a number of different studies that have calculated their own set of levelized costs for some of these different technologies.

And as you can see, the levelized cost estimates do vary from one report to the other. I think we do not actually find this very useful because really the devil is in the details.

You know, it does take considerable effort to really drill deeper into these reports, to really understand why some of the cost estimates diverge from one another.

This is also just to sort of illustrate some of the costs that -- this is what the costs we did derive for the 2007 report. This is a single-point, conditional set of levelized cost estimates. And I really say conditional because we've used a fixed set of assumptions for each one of these technologies.

Like one, capacity factor as opposed to we know that, for example, any advanced combined cycle units, the actual operating capacity factor has varied over the year. And that will actually affect the overall levelized cost estimates and what would be the revenue requirements for a developer.

PRESIDING MEMBER BYRON: Mr. Alvarado?

MR. ALVARADO: Yes.

PRESIDING MEMBER BYRON: Can you identify what you think is the single largest reason why the merchant levelized cost is so much higher than the others?

MR. ALVARADO: I think I might have to punt to some of our staff that actually were instrumental for coming up with a lot of these assumptions.

PRESIDING MEMBER BYRON: Good. If we have an answer, that would be helpful. But otherwise, I think we'll get back to this later. Do you have an answer?

MR. ALVARADO: Joel?

MR. KLEIN: Yeah.

MR. ALVARADO: This is Joel Klein, the project manager for the last cost of generation project.

MR. KLEIN: In this report the merchant costs are higher than the IOUs, which is the one you want to compare it against. Because the POUs have very low financing. They finance through -- they have no equity, they finance through debt, which means they have a noticeably lower cost.

But if you compare the merchants to the IOUs, the merchants in this report, and perhaps not entirely correctly, are higher because of the financing costs.

Now, in some actuality, and this is a subtlety we're having trouble capturing, IOU costs tend to be higher than merchant plants. And we finally traced this to a missing element. And the missing element is that we were using revenue requirement model for all these.

Merchant financing is not typically done with a revenue requirement model. It can be, it's not typically done.

We're going to incorporate this improvement in this upcoming 2009 version. And costs can decrease for merchants is in the range of 20 to 30 percent. So you'll see a shift in the levelized costs now. We expect to see, at least by and large, that the merchant plants will now be less due to the type of the way it's calculated. Okay?

PRESIDING MEMBER BYRON: Thank you, Mr. Klein. I think I do recall this coming up before, and so I thank you for clarifying that again.

MR. KLEIN: Okay.

PRESIDING MEMBER BYRON: Thank you.

MR. KLEIN: To make this short, this time we'll do a better job.

(Laughter.)

MR. ALVARADO: This is another chart that comes from the 2007 levelized cost of generation report that we prepared. And this is just to illustrate that some of the other factors that we have analyzed, and we will also evaluate this time, as the effect of tax credits.

So, this will show what would be the cost to the developer versus I would call them a social cost, when you consider the overall taxes associated with development of these facilities, too.

This chart is more the crux of the main point that we want to make to provide when we do these levelized costs of generation studies. In the last report that chart we provided is a single-point forecast.

But in reality, the calculated levelized costs can really shift from one direction to the other depending on the assumptions used in -- you consider for each different technology.

So this is just a sensitivity of varying different input assumptions, and we'll just show you how some of these assumptions will affect the levelized costs.

Like with the parabolic trough facilities, you can see the capacity factor, operating capacity factor of a plant can actually shift the calculated levelized costs for each facility.

And in this cycle we want to spend much

more time in understanding how all these different variables, in itself, could change. And also how it will affect overall levelized costs.

Another consideration is this chart just provides the cost estimates of different vintage reports, the 2003 report that was developed versus the one we did last cycle.

And you can see that the cost estimates, alone, have changed over time. And we would expect it to change. I think this is something -- this will be another key feature for this analysis is to understand what could happen in the future.

We hear many general assumptions about how the economies of scale may actually change the costs for developing one technology or the other. The costs of materials may vary depending on the economy, scarcity of resources, et cetera.

The application of this levelized cost generation project will be used not only internally but as we have had many requests for this information, we have had financial institutions that are considering financing different projects.

We will use this to really evaluate how these prices may change over time. We will use this information to analyze the financial feasibility of one technology project next to the other. And to do so we will develop screening curves to be able to at least show how some of these different technologies are comparable.

Of course, I would say screening only because cost is only one factor you consider when you're comparing different generation technologies, since the actual attributes and services that each technology can provide to the system is very different.

The energy efficiency program has also used these costs to evaluate the economic benefits of say, of expanding our building standards, or how any alternatives may compare.

And it's also an input to our resource planning studies. We do conduct -- we do develop alternative resource plans, trying to evaluate the implications of what would happen when you build out a wind resource into the future, and how the implications would change over time -- with comparing other technologies.

And the cost of some of these generation facilities have also been used as a benchmark for wholesale energy costs.

So, the next steps. At today's workshop we will discuss all the factors, the results of our study on the input variables for the renewable technologies, IGCC, nuclear generation.

Once we receive any comments, and if we need to modify any of these assumptions, they will be input to our cost generation model to calculate their range of levelized costs.

And as Suzanne indicated, this will be then a subject of the later workshop on July 22nd where we will present a staff report on all of our results from this project.

With that, I'm open to any questions.

PRESIDING MEMBER BYRON: I do have another, if I may. Mr. Alvarado, I'm not sure if the model included the effect of tax credits. You did show us a figure that showed the effect.

What about the price of carbon? Is there an option to include that in this model?

MR. ALVARADO: We have talked about adding that functionality into the tool. We've done that outside of the model, but I would defer again to Joel. I think we have discussed maybe adding carbon values to see how that might affect the levelized costs.

MR. KLEIN: (inaudible).

PRESIDING MEMBER BYRON: Mr. Klein, you'll need to come to the microphone again.

MR. KLEIN: Okay. This is Joel Klein again. We have a definite commitment to incorporate the mechanism. Now whether we're going to have agreed-upon carbon values to put into the model is very questionable.

In fact, I've been told that we probably won't. But I'll let Al finish that one.

(Laughter.)

MR. ALVARADO: Well, I think the target for any value of any carbon allowances or attributes really is a shot in the dark. But, at least with this tool we will be able to examine how different carbon values can affect the levelized costs of a plant. So at least we can do a sensitivity study of a different range of values.

PRESIDING MEMBER BYRON: Good. Thank you.

MS. KOROSEC: All right, if there's no other questions for Al, let's move on to Jerry Braun, who's going to talk to us about future energy costs.

(Pause.)

MR. BRAUN: Good morning, Commissioner Byron, Ms. tenHope, Ms. Chew. I want to say a couple of words of introduction in terms of how PIER's effort fits into the overall cost of generation work.

We are providing a --

PRESIDING MEMBER BYRON: Mr. Braun, go ahead and bring that microphone up closer so we can all hear you better.

MR. BRAUN: Sorry, sorry.

PRESIDING MEMBER BYRON: Thank you.

MR. BRAUN: Our task is to provide the data that goes into the levelized cost models. And this is probably at least a second iteration on that. And we have been working closely with Al and Joel and their colleagues to make sure that the data is in the right format, and is what they need.

And I would also mention that we have a number of our PIER renewables staff here when the time comes to answer questions on specific cost items and technologies.

I've titled this multiple moving targets. And I think what brought that to mind was my first exposure to levelized cost analysis was as, I won't say how long ago, but a very long time ago, as a young nuclear engineer.

And the burning issue of the time was whether the levelized costs of nuclear were 7.9 cents per kilowatt hour versus the levelized costs of coal at 7.8, or vice versa. And that was how complicated things were, and these were not moving targets. They moved over that range.

We now have a lot more targets and they're moving a lot faster. And so we have a bigger challenge.

Whoops, that's not the right place. I'm not done.

(Laughter.)

MR. BRAUN: So, what I'd like to do is emphasize the questions of the big things that change. Scale is a big issue. Commercial and industrial readiness is a big issue. And then within each generic category there is a great diversity of options.

So what -- we'll try to kind of illuminate these various ways things can change and why they change and how fast they can change, and what's driving things. And then talk a little bit about the research that probably needs to be done in the future to get a better grip across the board on renewable costs. And why we designed the study the way we did to support the cost of generation project.

I'd like to suggest a couple of issues to keep in mind as we go through the charts. And we'll come back to these. But we have a challenge to do cost estimation not only in the context of proliferating array of options, but also very fast changing cost drivers and very many cost drivers.

And we probably have a need for new metrics and methods, especially to evaluate variable resources such as wind and solar. Because, in effect, the levelized cost approach, revenue requirements approach, works very very well for baseload type generation. But -- it gives you a cost, but it may not be an evaluated cost.

And I should also mention that while today we're focused on central station renewable options, and other reference technologies, we have also included in the cost data generation effort an initial attempt to get a handle on community and building scale renewable technologies.

And this is kind of, on the left you see a long list of generic renewable options. And you'll notice that I've divided them into three categories. The ones that we're going to be talking primarily about today are utility scale renewables. But you're also aware that at the other end of the spectrum renewables are being applied on buildings. And if you scale up the building scale technologies, scale down the utility scale technologies, you have a wide range of community scale options.

And the thing that we need to remember is that in California certain of these options are commercial, certain of them are emerging, and certain of them are both. And that is there's a commercial industry, but there's also a lot of venture-funded development of new variations.

And likewise, we need to remember that while in the rest of the world many of the renewable technologies are commercially applied. In California the emphasis has been on utility-scale technologies. And if you look at the right-hand column, in particular you'll see really only one building scale technology that is in commercial deployment. Whereas there are several that offer very good cost effectiveness.

So, I won't go through the long list on the left because I've got some charts to cover that, cover each of those aspects. Resource to conversion technology, end product, equipment plant, financing and that sort of thing. And deployment experience.

But the point is that, you know, we kind of have a new ballgame as we look to how the RPS is to be achieved, and how other renewables deployment could be achieved. And there are significant issues of costs and risk that affect economic value and affect price.

And this is Al's chart. And just to point out that in order to generate data for modeling, the best approach really is to look at projects that are actually deployed as proxies for the generic groups of renewable technologies.

That way we can come up with the detailed data. But we need to recognize that they are just proxies. In particular, even the commercial technologies have a lot of variations. And then now that we're seeing a lot of venture capital going into the emerging renewable technologies, the variations are just proliferating.

So I'm going to start with resource quality, and just indicate that this is a cost driver. Using wind and concentrating solar as examples, you know, what we tend to do and what we're able to do is to provide an average resource quality that is the daily average output of solar, wind and those options.

But, in fact, the plants don't operate on average resources, they operate on what comes in every day. And there's a lot bigger variation on a daily basis.

And likewise, in some renewable technologies the resource varies. It actually -- and geothermal is a good example that I'm sure you're all aware of that when you exploit a geothermal resource it affects the long-term quality of the resource. And that needs to be managed. And it's a cost estimation issue, too.

The best example that I could think of of technology variations is the central station solar thermal, concentrating solar thermal power plants, and concentrating photovoltaics.

And as you -- the issue of scale comes in very heavily here. There is one technology that has been deployed at scale. The other, and that's the top left. The others have yet to be deployed at scale. And there is significant risk, whether it's healing up the power plant, itself, or scaling up the manufacturing of all of the replicable pieces of the plant.

And so these are not -- the costs will be different because these are -- financing costs will be different because of risk. And these technologies are at different points on their own learning curve.

Energy capture is another interesting question. A variation within each generic option, and particularly the variable renewables. If you want the maximum energy capture with solar, you aim something directly at the sun and concentrate the sunlight. And you can get efficiencies up to 30 percent and very high capacity factors.

If you want to minimize installation costs you simply lay things flat on a flat roof. And that, of course the sun is never coming directly perpendicular to that surface, so you're sacrificing energy capture in order to capture cost savings.

In the wind, relative to wind we have a

similar situation. You can measure the wind speed at one point, the hub of the rotor. And that should tell you -- that would tell you what would happen if the wind speed at every height were the same. But it's not.

And so you don't have a perfect deterministic power curve for wind turbines. So, another thing, performance affects cost, to the extent that we're looking at cost per kilowatt hour. Because performance determines kilowatt hours.

Enabling technologies are a factor that we probably are not dealing with well at this stage, but we need to in the future. It's probable, in my opinion, that solar and wind power plants will include energy storage in the future in order to optimize their economics and their profitability.

Utilities may deploy energy storage, but I expect that in some cases, or a lot of cases, long term the storage will be included in the plant, itself.

We also have variations in end products. We're talking about central station electricity here. But the question of how much of the resource is available for central station electricity when there are other end uses. And that, of course, effects sort of a competition for resources that will affect costs.

My view would be that the most profitable end uses for bioenergy will drive innovation and industry growth, and we don't know yet which of these end uses are going to be the most prevalent.

The other thing is that the value chain in biomass is particularly lengthy. And conversion is only one part of it. There's a long value chain in terms of collecting the fuel and getting it to the conversion point. And there's also a value chain beyond that in terms of collecting the output and storing it and delivering it.

So, this makes -- this is a particularly difficult cost estimation issue. And the data may not all fit into the models that we have precisely.

We know that manufacturing scale, particularly in technologies that use a lot of identical parts, can drive learning, or the scale of manufacturing can drive learning, as in the case of PV. So, market size and the rate of growth can be significant cost drivers.

And you have to be a little careful in looking at the learning curves on things like this, because there are -- sometimes things can change, as has happened in the last few years with photovoltaics, where the industry shifted to a higher, basically ran out of cheap materials and needed to switch to more expensive materials. Which, you know, changes the dynamic, changes the learning curve.

And it also actually, as you can see in the little inset, some significant volatility in the rate of demand growth and the rate of revenue growth, and the module prices.

And within each category of renewables, and I've used photovoltaics as an example here, the material cost drivers are different because the materials are different.

And each source of materials, as you look ahead to very high volumes of deployment, you have to look at the supply curves for those materials. Crystalline is abundant, silicon is abundant. Some of the other materials that are used in thin film and for as kind of doping and other materials in the manufacturing process, are not as abundant. And their prices affect cost. And will depend on how much of them is used and how they're produced.

Again, in many cases, we're kind of piggybacking on other industries in terms of the materials that are available for photovoltaics manufacturing.

Plant scale. You would think that on thermal power plants there'd be an optimum scale. On a geothermal, the geothermal data for California suggests otherwise. And thermal power plant scale really does affect the cost of the thermal power plant.

My guess is this factor of ten spread in plant size is probably related to other factors other than optimizing the conversion plant. Resource collection and so forth are one thing, and then regulatory factors are another that would drive plant scale. But plant scale, in turn, drives costs.

PRESIDING MEMBER BYRON: Mr. Braun, was that last -- was that dollars per megawatt hour?

MR. BRAUN: No, I'm sorry, that isn't properly labeled. It is megawatts, actually.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. BRAUN: Another case is where you do have the option to make the power plant, renewable power plant pretty much what you want it to be, using thermal storage. And with thermal storage you can vary the capacity factor of a solar thermal power plant. You can also vary its ability to deliver power on peak, and when you deliver power over the course of the day.

And our models, our levelized cost models, really take into account, you know, you can specify what the plant will do. And guess at what, you know, what amount of storage will be used. But, in fact, the decision on what will be done is ahead of us and will depend on, you know, probably the configuration of the plants will depend on the level of penetration and how the market is structured to value the things other than kilowatt hours.

Equipment modularity is a factor in costs in the sense that they're inherent modularities. I've used a couple of examples here, going back to the solar dish technology.

Typically the progression would be from, you know, small scale to larger scale, to larger scale, to larger scale, to larger scale. We're seeing some projects that go directly from one module to 10,000 modules. And, you know, that is not a typical progression in terms of commercialization of a technology.

So we may see some of these technologies deployed in entry markets and intermediate markets, as they scale up. And that also will affect their cost in getting to the complete economy of scale.

This is more of a price, I guess, than cost. But I wanted to mention it. You know, the photovoltaic module and others, a case of that technology, is the same whether you put it on a home or in a large array on the ground.

However, the cost of everything else varies significantly so that even though the most expensive part of a photovoltaic plant, you know, it costs the same no matter how you use it, the cost of energy from a central station plant is probably less than half of that for a residential roof. Because of the costs of transacting business in the market, primarily.

And so, you know, it's kind of fortunate in a way that the commercial rooftop projects are financed against avoided commercial utility rates. And the larger projects are project financed against the wholesale avoided costs. And so it kind of balances out. You got, you know, you got lower prices, but you have lower cost systems.

And this is something I wanted to bring up, too, because this is something that did happen at one point in one case. And it's not really happening now. And it's a major issue, or major factor in reducing costs.

You may remember the solar thermal power plants that were deployed in the '80s, eight separate projects, spaced one year apart. Six of them were exactly the same size. And because of that replication every plant that was built was based on what was learned last year. And the costs came down very very nicely.

If we could figure out a way to replicate that kind of process, and I suspect the policy tools to do that are lacking, but that would go a long way toward taking renewable power costs from where they are today to where we would like them to be for the large-scale deployment.

I said I would come back to the issues

of kind of in the sense of what we're doing about them, what we would recommend be done about them. I really do believe that the best thing we can do, along with the kind of snapshot we're doing here every couple of years on costs, would be to really dig into the costs of the technologies and the options that are commercial, that we think are most likely to be deployed on a very large scale. And really understand how their costs are affected, not just by our experience in California, but by the global, the dynamics of the global market.

And I would mention to you that we have four renewable energy collaboratives that are doing research in renewable energy. And one of their tasks is to help us understand costs in a more in-depth way. And so we, in the future, would expect some contributions from these collaboratives on the subject.

The other issue is metrics for evaluating variable resources. And I'll focus on that in particular. It's interesting that when renewable costs -- I do remember this, too, when renewable costs were so -- when there was really only one renewable option that anybody was looking at, it was solar thermal.

And nobody cared about the costs, or the utility industry didn't care a lot about the costs because they knew it was expensive. But hoping that the costs would come down.

And so the way it was evaluated was not by looking at its levelized costs, but by basically plugging it into a model for the entire electric system. And the model optimized the mix of resources and so forth, and gave you a number which was the cost of electricity generation every year for the whole system.

And plugging solar into that model and comparing what the total system cost would be with and without solar gave you a value of solar at different levels of penetration and with different amounts of energy storage.

And I really do think we need to get back to that way of looking at the variable renewables because it's a more robust approach that gives you a sense not just of what they cost, depending on what you assume for their capacity factor, but what other avoided costs are produced in terms of both the rest of the generation system and the transmission system.

Now, to the study that we've commissioned to generate data for the cost of generation project. I mentioned that we're trying to simplify our task by focusing on commercially established options and proxies that are, you know, where the data's available. But also assessing the potential for future technology shifts.

And I think your question, Commissioner Byron, related to the difference between merchant and IOU and muni financing kind of got to this. We need to sanity check the cost estimates using price data from the market. And that's something that's part of our scope.

We need to model the evolutionary changes based on our understanding of the cost drivers. And we're doing that.

And we are also, just so you know, we're focused on central station costs today, but we are going to take a preliminary look beyond utility scale at the other deployment levels.

So, in summary, we have quite a bit of data on utility scale options. And a lot of project development going on. Community scale, there's some pilot projects and a lot of regulatory barriers. Building scale, photovoltaics is certainly approaching an energy-significant phase.

And, in general, across the entire spectrum of renewables we basically just have a lot of escalating diversity and endless variation to deal with.

So, the consultants study is really designed to do two things. First, support EAO and the IEPR process, and the project that's supporting the IEPR. And then also to bridge to what I would call a more aggressive or more comprehensive analysis of future costs.

And this is the place where my thank-you slide actually belonged, so, thank you.

(Laughter.)

PRESIDING MEMBER BYRON: It's always good to start at the end. Mr. Braun, very good presentation. And thank you very much. I chuckled on the second bullet in your summary about the diversity and endless variation. I suspect that will continue. And we're going to see more.

We're going to see better designs and we're going to see more efforts to squeeze out a little more efficiency here and there, particularly when we get into the storage issues.

You know, some of these technologies I actually worked on as a young engineer, as well, after my nuclear period, concentrating Stirling engines and troughs, almost 30 years ago.

And while you were speaking I was thinking, have you had a chance to look at some of the designs of these large utility-scale projects that are being considered at this time?

MR. BRAUN: Yes, I've had a chance to look at some of the newer ones. It's quite interesting. You know, the creativity in trying to differentiate from the current offer so that you can attract venture capital funding, it's an interesting stage.

PRESIDING MEMBER BYRON: So I know your analysis is technology-based. We include the costs of land in all of this, and the mitigation of land that may be necessary. And maybe the unknown development costs at this point. Do we consider that kind of factor, which we never did before. Do we look at that now? It could be substantial.

MR. BRAUN: Technically, yes. I believe

that's true. Have we looked at it in the -- maybe in the context we need to in the future, which is, you know, the environmental -- what needs to be done to accommodate to environmental concerns and those sorts of things, we haven't really started to do that. I think that would be part of the more comprehensive analysis that we need to do.

PRESIDING MEMBER BYRON: I think it's going to be more substantial than we thought. Well, thank you, very good presentation.

(Pause.)

MR. HINGTGEN: Well, good morning. I'm John Hingtgen from the energy generation research office in PIER. And I'm going to present a brief overview of the renewable study that we are having done, at the outline level. I'm managing the renewables portion of this for the Commission.

I'll give an outline view of the study scope and schedule. Then we'll have the presentation by the consultant that the Commission has hired to do this work. Following that will be questions and comments here in the workshop. Then there will be a comment period of one week from today. And then following that we'll use the input in final results that will be prepared for this work.

So the study involves six tasks within its scope. The first four of these tasks will be looked at here today. First we're going to identify the commercial renewable energy technologies in California and their scales of deployment.

We'll look at marketing and industry changes affecting costs, current trends and cost drivers for each technology. We'll provide current costs with minimum and maximum costs for the recommended technologies. And then create a model to estimate future costs using current costs and cost drivers.

The final two tasks will be not reviewed today, but they will be ready in the future in June. That is to reconcile prices and costs for utility-scale purchases considering factors other than costs and the pricing. And then to estimate costs and cost trends for community and building scale technologies and explain cost variations.

The final results for all tasks will be ready in August.

So to break this down a little bit further. The first task we're going to be identifying commercial renewable energy technologies in California. First by reviewing key studies by the CEC and other agencies that have looked at this. And then recommending particular technologies by scale for detailed analysis.

And this will be broken down into three size groups, as Gerry alluded to, the larger utility scale of over 20 megawatts; the community scale of one to 20; and then building scale of under one megawatt. And the community and building scale results will be ready later.

The commercial embodiment of each technology will be identified now and ten years out from now, in 2018. And for this study we've included nuclear and IGCC technology also as other low-carbon electricity sources.

And the second task we're looking at cost drivers, identifying market and industry changes since the last cost of generation study in 2007. Identifying trends that affect cost; and then identifying specific cost drivers for each technology. For example, the scale of a plant would be a major cost driver.

And the third task, current costs are

being examined. Current costs more in the recommended technologies, nuclear and IGCC, are being provided. The format of this is going to be in a format that's useful in the modeling effort of the electricity analysis office over the larger cost of generation modeling of all technologies that are significant in California.

And then maximum and minimum costs for the recommended technologies are being provided. In this context, the maximum cost is one that more than one competitive market player would pay. And a minimum is the cost that the lowest cost that's been recorded for commercially representative projects.

Finally, the fourth task, trajectories of costs are being looked at. We're going to be developing a model using the cost driver information to estimate future costs for the 20-year period for utility-scale technologies. And then refining this model by looking at current costs with it.

So, in summary we're looking at particular renewable technologies, nuclear and IGCC, deployment at the utility scale, data that can be used as a format for the cost of generation modeling. And then considering the implications of this for broader energy planning and policymaking in California.

Comments will be taken up until the 23rd at 5:00 p.m. To comment indicate the docket number and the title of this workshop. They can be either mailed or delivered to the dockets office here at the Commission. If they're emailed, please also send a hard copy.

Now, I'd like to turn it over to our consultant, which is KEMA, and introduce them and their team. KEMA is an international energy consulting firm with headquarters in the Netherlands, and a U.S. subsidiary.

They have approximately 350 staff in the U.S. with expertise in energy markets, distribution and transmission, renewable energy, distributed energy and energy efficiency. And they have amassed about 30 years of energy experience in the U.S.

So, I'd like to introduce Kevin Sullivan, who is the technical leader of the KEMA team. And then he'll call upon others on their team as appropriate at the right time.

MR. SULLIVAN: Good morning. My name's

Kevin Sullivan with KEMA. And just a little bit of background. I head up what we call the market issue generation services.

I will be bringing Chip O'Donnell to share some of the load as we go through a tremendous amount of material that you have in front of yourselves. So it will also save my voice, because I did lose it earlier on this week. So, please bear with us.

I first would like to say that this is a huge opportunity for the industry. I want to acknowledge the leadership shown by the CEC team. And certainly the collaborative nature of this study has been an excellent part of forming the leadership, not only in California, in the United States, but also globally in the direction of renewables.

We've actually got a fairly large agenda here to go through. I'll spend a couple of minutes talking about the approach and methodology. And then we will swap out between Chip and myself to go through the various technologies that we have listed here.

I think the approach and methodology, and John did a good description of the various tasks that we have to address as part of the study. But I think the critique of the existing documents has formed a very good basis. The 2007 IEPR report formed a good platform to build the deltas and the differences that we see, not only in cost of generation, but also in the change in technologies. And the mix of central plant technologies that we selected.

The important thing to look at is the recommended utility scale renewable energy. When we go through that list you'll see we have a variety of different technologies including fossil-based technologies. And I think that shows a lot of leadership and insight to make this report a lot more valuable for the industry in general.

The overall process that we followed was first of all, to review primary documents that we have as reference documents that the CEC has done in the 2007 IEPR. And looking at the review of that existing material generated a augmentation of that knowledge, with a global database. In fact, we used a lot of our global reach into Europe to make sure that we would actually look at technologies that are not just present here in the

United States, but also manifested in Europe to some extent.

There is also a, I'd like to say something about modeling. I think you have a great model here, but we have used a collaborative exchange with the GreenX group in Austria, that also cover a modeling technology in a different fashion for the Europeans.

Taking that input we then looked at an update for the renewable energy technologies. In parallel to that, we looked at the industry input and the cost drivers.

In the handouts that you have you will see qualitative statements regarding cost drivers. There's a lot of further detail that will be done in putting that into quantitative data as we go forward.

The other input was very important for us, is the industry has put on production and the actual delivery costs for these various renewable energy technologies.

That merged into the final box on the right-hand side here which is really the market trends and the future projected costs, which forms the input for the esteemed model that you have for doing levelizing costs. And the data that you have actually is the input data in its raw form that'll eventually go into the levelized cost model.

I thought it was worthwhile spending a bit of time just talking about the technology selection criteria. And as you'll notice that the list that Gerry and John and Al mentioned is very different in some aspects. First of all, in size and in appropriateness for the market, as the moving parts in the market change.

We looked at what technology was commercially available and who's using it. We also looked at how many projects there are worldwide, and have the started, and what phase these projects are in.

And then we took into account the commercial nature of these projects. And you'll see some of the things like capacity factors that we have in our data is based on actual averages that we see from plants that are actually delivering. Very different to what maybe could have been the planned capacity factors for the plants that were done in prior reports.

And then we looked at, you know, are

there any things that make it difficult, and is the technology viable in California. And, you know, one of the subjects there might be nuclear. But a very good benchmark to have nuclear in the mix of technologies that we looked at.

Along with that we looked at around the world what's commercial, what's being produced, what new technologies coming up. But, again, looked at what's viable in California. And then took some consideration for the political climate in the area.

So the list that we have actually to review is fairly extensive, but I'd like to just make a few comments to the sizes. And the approach that we took was if you look at the gross capacity numbers in megawatts, first of all the list, itself, in the vertical form is different to the original 2007 IEPR report, based on what we think are commercial technologies today.

But secondly, the sizes and the megawatt sizes are designed to be modular. So, for example, a offshore wind class 5 you could see a megawatt capacity of 350 megawatts. It could consist of various phases of 50 megawatt windparks put together.

Another example would be if you look at solar parabolic trough. You have 250 megawatts as a size. It could consist of five 50 megawatt steam turbines.

So it was very important for us to look at modularity so that we could actually drive the cost of generation in that direction.

The other point on the extreme right on this list is to note that some technologies we deemed were not really commercially viable until 2018. And just to point those out, the biomass IGCC technology, while it's very exciting, is a scale issue and probably look at that starting in 2018.

We also took the time to look at the wind, obviously doing onshore wind is a priority before you do offshore wind. In most cases when we can capture a category 5 wind onshore we'd rather do that, than to do the offshore. So we looked at that starting 2018.

And there's still a lot of developments in that area, and we'll come onto those as we go through.

And then wave action is a very nice demo environment today, but not commercially viable.

Probably we hope that by 2018 we'll see some commercial viability there.

PRESIDING MEMBER BYRON: So in the offshore wind, of course, in Europe, Denmark particularly, there's been a lot of offshore wind that's been operating for a long time. So why would you class this as being something that's start data is at least another ten years out?

MR. SULLIVAN: Actually we have the cost data that could be deployed earlier. But it's very location-specific. And depending on geography's depth and/or mounting technologies, the cost to generate in the offshore environment is very difficult to levelize.

We think that'll become a little bit more routinized as more people go and do that offshore around Europe and certainly Holland.

So I'd like to start with a group of biomass technologies. The map of the U.S. showing biomass resources is indicative of the reason why we selected basically four types of biomass technologies.

We're going to talk a little bit about the using stoker boilers, which is very conventional. Also fluidized bed boilers. But very exciting to look at, also, biomass cofiring. And when we use the word cofiring, just from a terminology point of view, we mean taking existing coal-fired power plant and burning a certain percentage of biomass in that power plant. And what you're doing there is replacing coal Btus with biomass or renewable Btus.

And then another exciting technology is, of course, the biomass when you can take syngas and use it in an IGCC process.

So, there's a fair amount of material here. We'll go through it fairly quickly because I think most of you have copies, but I think the message here on stoker boilers is that it's a very standard technology, been around for many years.

The idea there is that you can actually have a biomass thin layer at the base of the boiler and burn biomass fairly effectively using a stoker boiler. Very mature technology. So that's another reason why we selected it. And also selected it in approximately 40 megawatt unit sizes.

Example here on the left is a woody biomass stoker boiler. These are the kind of boilers that have been -- there are a number of them around the United States. So, very commonly used technology. It is not the most clean-burning process that you could have.

So, hence, we looked at the cost drivers. One of the things about burning biomass in any boiler technology is really the type of biomass determines a lot about the viability and cost of generation. And also the availability and the reliability of that biomass source will determine a lot to do with the capacity factor for that.

So fuel transport and handling are big factors. We think the boiler island costs, of course, in all these costs of -- cost drivers, of course the plant is a major cost driver in all cases.

But the cleanup required in either SCR or SNCR technology, catalytic technology, is also key, an economic cost driver in burning biomass.

And a big factor is whether you can play into an existing plant with a biomass plant, augment it into the existing infrastructure, or whether it's a greenfield plant.

The kind of sizes we looked at was around about 38 up to 40, and in the low case, 25 megawatts, to come up with some cost data for this kind of plant.

I think it's probably on the current cost it's clear that you'll notice that sometimes we mix up here dollars and gigawatts and megawatts. Apologize for that error.

But we're looking at a fairly low-cost initial cost, and a fairly good perspective in the cost projections for this kind of technology.

Moving on to the fluidized bed boiler. The neat feature about this technology is that it creates a fire boil, if you like, within the boiler, itself. You get much more effective combustion. It actually looks like a fluidized mass of biofuel within the boiler, itself. And as you get more complete combustion your pollutants are lower, and your heat factor and Btu transfer from the biomass is much more effective. So you have a flexible fuel capability, and good emission characteristics.

An interesting plant, actually, on the left in this diagram is one in Minnesota. It's about a 70 megawatt -- turkey litter is the correct word, I think, to use. But it is a --

PRESIDING MEMBER BYRON: Is that the

name of the plant or the fuel?

(Laughter.)

MR. SULLIVAN: That's the name of the fuel. And they've managed to keep the environment such that you cannot smell the fuel. But that is also a very good proven technology, not used very often in biomass, but the fluidized bed boiler is well proven. A higher carbon burnout, of course, which is important for the environment. And it shows that you have more fuel flexibility. And when you're dealing with biomass, don't expect consistency.

So, relatively low combustion temperature also important. And the one aspect is to look at the sulfur emissions, which is an important part of the pollutant controls.

And, again, here the supply of the biomass, itself, as you can imagine when you're dealing with turkey litter, one, you have to try and transport that so that you don't cause accidents on the highway due to obnoxious smells. But it's also the transport handling is fairly expensive. The boiler island, itself, is expensive and the O&M costs are fairly considerable.

Those are main drivers. We also see, looking at about 28 megawatts was the model size on the turbine and the boiler, and we came up with projected costs that are fairly reasonable and viable, assuming you can have the supply chain in place.

The cofiring technology, I mentioned that earlier, is something there's been a lot of discussion about. And the reason why, I think, the leadership of the team adding this to the list of technologies is very key.

This is one way you can use existing infrastructure and inject biomass into various parts of the combustion process in order to optimize and replace, if you like, fossil fuel emissions.

So, you know, this diagram gives you an idea of a very large existing power plant shown here, where a single unit within that plant had around about 20 percent cofiring. When we use the figure 20 percent, we mean 20 percent electrical equivalent. So if you have a 100 megawatt boiler, electrically 20 megawatts would actually be derived out of a cofired biomass fuel source.

So, cofiring technology makes use of

that existing coal-fired infrastructure. There's a lot of experience being gained where to inject and how to best insert biomass into an existing power plant. And the modifications are not too significant. It's all on the fuel-handling side, not so much on the downstream electrical conversion process.

Key drivers, of course, again the supply of that biomass. And, I think, the reluctance that a lot of operators have in having to deal with an intermittent supply of biomass. Or even burning something that isn't nice, clean coal.

So there's those kind of factors that determine cost. Of course, you need real estate for storage. You need the fuel feed quantifications. And you need to check on the emissions, particularly the selective catalytic reductions, because the contaminants coming out of the biomass flue gas can actually affect the deterioration of catalysts in these power plants. And affect your SCR.

PRESIDING MEMBER BYRON: Mr. Sullivan, we have very little coal being burned in California. Are you aware, how many plants are doing this throughout the rest of the United

States?

MR. SULLIVAN: I believe the number is close to about 20 plants, in various stages. And I am aware of the fact that probably every coal-fired power plant that has local woody mass biomass available has done a study to analyze the effect of cofiring. And we've been involved in that effort.

So, we're excited about a lot of these going forward. And we do realize that in California, you know, four or five plants that are coal-based. However, in meeting an RPS maybe the neighboring states could contribute. And just replacing some of that coal with biomass has a huge effect on the RPS emissions, assuming biomass is seen as a renewable.

PRESIDING MEMBER BYRON: Thank you.

MR. SULLIVAN: And if you look at the cost projections, you know, because you're dealing with an existing asset, an optimizing existing asset, you know, the cost range you can see on this chart is very low compared to the other forms of renewable on a megadollar per megawatt basis.

PRESIDING MEMBER BYRON: So this is an incremental cost essentially -- making changes that are necessary to --

MR. SULLIVAN: Correct, yeah. This is only the cost associated with making modifications to an existing plant. And we picked a 100 megawatt unit to model.

MS. tenHOPE: I think there's a typo on the cost where the -- or they're transcribed between the average and the high cost? You might just want to take a look at that, because the average is -- am I looking at the right one?

MR. SULLIVAN: Yeah, I think you're quite correct. We picked up a couple of typos --

MS. tenHOPE: Oh, no, it was on slide 16, sorry.

MR. SULLIVAN: Yes. Thank you.

Biomass used to create syngas, and then that syngas going into an integrated gasification combined cycle is the fourth technology that we studied.

And this is the one that I indicated would be much more viable around about 2018. But it is an interesting process because of the efficiencies involved in converting the biomass first into a gas, and then using it in an integrated gasification combined cycle plant.

So, key characteristics, of course, is the direct single stage and -- thermal pressurized fluid beds gasifiers that need to be in place. Heat exchangers that operate around about 400 degrees C. And the nice thing is that you're burning clean gas in classical gas turbines. And the residual heat is used as part of the steam cycle, as well. So you can take the waste heat and reconvert that in a combined cycle process.

I think this technology gives biomass an access to much greater efficiencies. Certainly in gas-fired power plants, the deployment and utilization of existing gas turbine technology is enabled here, as well. So the commercial deployment, I think, is a very exciting operation.

There are some plants that are running in Europe, and a lot of the data we're collecting are based on more or less pilot plants that have been put in place for this kind of technology.

Again, the cost drivers end up always being the fuel, itself, and the emissions. And, of course, the type of gasification used, whether using the shell process or FB, and I think some other OEMs have license agreements on the gasification process.

The costs, of course, are very close to where you would expect IGCC technology to be -- combined cycle gas turbine technology to be, with the additional cost of the gasification of the biomass.

I was hoping to take a break here and introduce you to Chip O'Donnell. Chip's been with KEMA for a short period, but comes with huge industry experience. And, Chip, if you could take over from there.

MR. O'DONNELL: Good morning. My name is Chip O'Donnell; I'm a vice president and market issue principal with KEMA, and I am in the power generation services arena. And also have an extensive development background in both clean and renewable energy projects. Today I'm here to talk to you about the geothermal technologies that we've evaluated.

Really there are four different types of geothermal technologies, and the two that we focused on as being the most commercially viable are the flash power plants and also the binary power plants.

There are combination plants and hybrid plants that combine the flash and hybrid technologies, but in terms of commercial viability our research team felt that both the flash and the binary plants were the most commercially viable for the purposes of the cost of generation study.

The first type of geothermal plant, the binary plant, basically is a closed loop system in terms of the geothermal wells that are sunk into the ground. The binary plant basically takes an organic rankin cycle, which is a separate heat transfer and exchange circuit that extracts the heat from the ground and then passes it through a power turbine going into a generator and into the power process.

And so what that does is it basically separates the heat streams so that any of the production well material basically stays within its own closed circuit and gets injected back into the thermal reservoir.

Looking at the key cost drivers in terms of binary geothermal. And I think, Commissioner Byron, you had mentioned this before in terms of land acquisition and site geography.

For geothermal, one of the key cost drivers is first the identification of the geothermal resource, and then the development of the site, itself, in terms of land acquisition, in terms of permitting and in terms of test well validation of the resource. And that can take often substantial time. It is somewhat variable in terms of approach.

The turbine island cost is also a key cost driver in terms of the equipment and the production of that equipment, although I think that is now stabilizing in terms of our view of the experience curve in the industry.

Commercial companies such as Ormat have done a good job of commercializing and levelizing those equipment costs over time.

We've talked about exploration and confirmation drilling as a part of the site geography and acquisition and development process. The one thing that I would say from a development standpoint that comes into play with geothermal is that oftentimes, just like drilling for oil, gas and other natural resources, sometimes these processes can be variable as the technology is commercialized by a private developer or a utility. And so there is some variation and variability in terms of the realization, in terms of time. And time sometimes can affect the cost, which would then affect the levelized cost of the project.

Other cost drivers for binary are the steam gathering, itself, and gathering the resource into the plant, the royalties that are often paid to the landowner, and the overall operation and maintenance costs for the power turbine and the steam cycle.

And I think one of the things that you see in terms of the overall cost is that the overall cost in terms of installed cost is somewhat higher than that of biomass. The other aspects is that the overall emissions profile for geothermal tends to be a lot lower.

So from an environmental standpoint, it tends to be a bit more friendly even though the first cost of internal production is a bit high.

PRESIDING MEMBER BYRON: Mr. O'Donnell, is the blue line on top of the magenta a line there, are they coincident?

MR. O'DONNELL: Yes, that's correct. And the idea around that is that the cost for most of these plants are done within the same year that they are produced. So, there isn't a time lag in terms of the initial production and determination, and then the realization of the project.

The second type of geothermal technology that we've evaluated is the flash cycle. And basically what that does is that the heated water under pressure is separated in a steam separator into steam and hot water.

Then the steam is delivered into the power turbine producing power. The turbine powers the generator and the liquid is reinjected back into the thermal reservoir.

So what you have here, and this is one of the more common geothermal technologies, is that the actual production well and the flash steam from the well ends up going through the power turbine directly without the benefit of a closed cycle.

And so sometimes, depending on the nature and the characteristic of the production well flash steam, you can get overall environmental emissions as a result.

Overall, very similar in terms of flash, very similar cost drivers to binary. And that would make sense because the only difference between the binary and the flash is the type of cycle that is used once the geothermal, steam and heat source is extracted from the production well.

So you have the same site geography turbine island costs, exploration, confirmation, drilling and gathering costs, and then royalties and O&M expense.

One of the things to note in terms of the data that we see is we also see an emissions profile coming from flash geothermal technologies.

The nice thing about both geothermal technologies is that the overall capacity factors that can be realized are quite high once you've validated the production thermal source. And so that is something in terms of reliability of the renewable resource that can be quite helpful in terms of an overall energy and levelized cost strategy.

And, again, relatively consistent values in terms of geothermal dollars per megawatt, in terms of cost again slightly higher, but still in the ballpark range with biomass technologies.

The next technology that we'll evaluate is hydroelectric technologies. And basically hydro has been around for, you know, hundreds of years. And I think the key is looking at the different types of technologies that are available and that are available to the state of California in terms of production.

The types that we've looked at overall is impoundment hydropower, which is typically the normal dam hydropower where water is dammed, and then the water passes through a penstock and power turbines to generate electricity.

There are other types of hydro, as well. Run-of-river hydro utilizes basically the running flow of the river. And you see a lot of that in the Pacific Northwest and WAPA.

And one of the aspects of run-of-river hydro is that sometimes run-of-river hydro is not always controllable. You get what you get from the resource depending on the flow of the river and the -- between the turbine penstocks and the river, itself.

And then there's another type of hydro power that's used, and that's diversion hydropower. And that's where you actually take a slipstream off of the river source, the hydro source, and you run that through a canal and a penstock and a turbine which produces electricity.

The most common type, as we've talked about, is the impoundment or dam facility similar to Hoover Dam. And the nice part about the impoundment hydro resource is that you can control it. You can control it to create more electricity generation or less, depending on the needs you have of built-in storage reservoir based on the dam.

There are obvious environmental impact issues, as we've seen, not just in the United States over time, but also in China. With Hoover Dam and the environmental protection of the Salt River Project, as well as the Three Gorges Dam in China and the environmental impact that impoundment hydro has.

In conduit hydro tends to be a bit more environmentally friendly in terms of environmental impact. You're taking a slip stream off of the river, so most of the river remains intact.

When we looked overall at hydro we selected different size ranges that I think are one of the key cost drivers as we look at the cost of generation in the study.

Hydro is so site-specific and so resource-specific that there is a wide range, and a wide range of variation, in terms of not just the generation cost, in terms of the generation time to realize a project, but also in terms of the type of technology that's utilized.

It very much is based on looking at the available resource, and then matching the most optimal type of technology to that resource.

And so there's a wide band and a wide range of variation as we look at small scale hydro, from 1.5 megawatts up to 30 megawatts in size.

We've talked about the site geographies as a key cost driver. Licensing and permitting is also another key cost driver. And in the realization of power projects, especially hydro projects, obtaining licensing and permitting can impose not only significant costs in terms of obtaining those permits, but also in terms of the time it takes to realize those permits. All of which would affect the overall cost of a project, and ultimately the levelized cost of generation.

Measures that would need to be taken in terms of environmental mitigation, protection of wildlife, protection of flora and fauna in a hydro project is also a key cost driver. It's, you know, I think relatively assumed today that any type of hydroelectric project will have to take into account protection of wildlife and the minimization of the impact of the hydroproject on the environment and of the native species in the river and the surrounding region.

Fixed and variable O&M is also a cost driver when it comes to small scale hydro. Not just in terms of maintenance of the turbines and the turbine penstocks and the canals which require periodic and upkeep just like any other rotating generating equipment.

And then finally you have an annual charge that's levied by the Federal Energy Regulatory Commission in terms of hydro resources.

PRESIDING MEMBER BYRON: Excuse me, Mr. O'Donnell, I wasn't aware of that. How substantial is that Federal Energy Regulatory Commission charge?

MR. O'DONNELL: Eight percent, Pete? Roughly?

MR. BAUMSTARK: It's about $2.40 an installed megawatt is what it works out to be, something -- that's not right -- installed kilowatt.

MR. O'DONNELL: Right.

PRESIDING MEMBER BYRON: Okay, would you

mind repeating that so we can hear it on the microphone?

MR. BAUMSTARK: I have to look it up --

(Pause.)

MR. BAUMSTARK: Yeah, I'm Pete Baumstark from KEMA. It works out to be, and I'll verify this real quick, it's in my laptop, but it's about, I think it's like $2, you know, $2, $3 per installed kilowatt, or, you know, is about the range. But I'll look it up, and if it's any different at all, I'll let you know, so.

PRESIDING MEMBER BYRON: Thank you.

MR. O'DONNELL: One of the interesting things about hydro in terms of its development as a renewable resource in California and looking at the cost of generation, is that hydropower in terms of its overall cost, I think, can be quite competitive in terms of the overall dollars per megawatt in installation costs.

And because of the resource being natural water, flowing water, the overall installed costs of operation tend to be fairly low, as well.

So I think that's one of the reasons in the past why we've seen the development of the

Pacific Northwest hydro resources. But it also bodes well, I think, for the future in terms of looking at renewable energy as a broad mix of technologies, hydro certainly seems to have a place in the mix.

The other issue that we looked at in terms of commercially viable technologies for hydroelectric power is the opportunity to capacity upgrade existing sites with power.

And one of the issues that drives the technology choice around capacity upgrades with hydro is the fact that many hydroelectric resources were developed years ago and sometimes decades ago.

And, you know, when you have these large vertical penstock turbines people tend not to want to replace or upgrade them very often. They're big, they're heavy, they're quite substantial.

And so the ability to upgrade with newer technology, more efficient technology can be a benefit in terms of taking a resource that's already developed and getting additional incremental power out of it through improved technology.

I think one of the key things in terms

of capacity upgrade with hydro is the ability to get the upgrades. And we looked at upgrades from as small as 2 megawatts in terms of upgrade, to 80 megawatts, and even up to 600 megawatts.

So there is again a wide range of variation, I think, attributed to the wide range of variety, types of hydro projects that currently exist in the technology base today.

I think the most important thing in terms of capacity upgrades and cost drivers is the look at the existing power projects where capacity upgrades are possible, and looking at the cost to upgrade.

So you have a wide range of variation. If you look at the asymptotic graph on the upper right of the slide, going from $1500 per kilowatt all the way down to close to $500 a kilowatt as your scale goes up. And so there tends to be a very much an economy of scale in terms of the cost of improvement versus the size.

And then looking at capacity upgrades, similar to biomass cofiring, where you're augmenting an existing resource, the capacity upgrade, I think, from an overall cost profile perspective, looks promising in terms of our initial draft study that the research team has performed.

Because in terms of dollars per kilowatt, $770 per kilowatt, you're basically, at that point, under a combined cycle gas turbine project. And so I think with the capacity factor that a capacity upgrade to hydro produces, you have an incrementally low cost way of augmenting environmentally clean, reliable power.

PRESIDING MEMBER BYRON: Mr. O'Donnell, is that primarily just a technology upgrade? Just an efficiency improvement? You're not talking about adding additional flow capacity, correct?

MR. O'DONNELL: You could also add additional flow capacity, or increase the capacity of existing canals that are there. And I think, as we looked at it, we looked at the opportunity to do both. Whether it be through technology or through increased flow through the system.

PRESIDING MEMBER BYRON: Now, I'm going to suggest that we're about half way to lunch and you're about half way through the presentation. Let's take a ten-minute break.

MR. O'DONNELL: Okay.

PRESIDING MEMBER BYRON: Okay?

MR. O'DONNELL: Thank you very much.

PRESIDING MEMBER BYRON: We'll reconvene at 10:50. Thank you.

(Brief recess.)

PRESIDING MEMBER BYRON: As I recall, we were going to pick up on the solar on about slide 43.

MR. SULLIVAN: Correct. We actually studied two solar technologies. One is the solar parabolic trough. And you'll see by the data that we collect, that is an exciting development. And we've certainly seen a number of projects in that direction.

Of course, the technology, I think everyone's familiar with, but just to briefly recap. We chose a modular size of 50 megawatts, which is kind of a turbine component size.

But essentially you're capturing the thermal heat and culminating it into a pipe. And putting it through a heat exchanger. And, of course, the nice thing about solar parabolic trough is it ends up turning a steam turbine, which turns the generator. And we like that, spinning equipment. Because we know that technology well, so it's a very -- the way to look at this is really just a solar boiler, where the fuel is actually the thermal heat.

So there are various means of collecting that heat. We've seen a lot of improvements in the collection technology, the mechanical equipment associated with the tracking of a single access parabolic trough system.

So, a number of projects, in fact a lot of the cost data, we believe, is transportable from the models and the projects that we've seen in Spain. They've got a number of these projects running.

Of course, Nevada has also Nevada Energy and Solar Millennium Project. And the Arizona project is one that's fairly current.

But as this technology gets more and more deployed, we also want to just point out a similar thing to cofiring of biomass is happening here. Some customers and utilities are looking at can you augment my existing steam cycle with a solar parabolic trough system.

So that is a really exciting development, because you saw the numbers that you have when you do cofiring. If you can use the existing infrastructure of a steam turbine generator plant, transmission and generation, and replace the coal energy with solar thermal, and a steam circuit, that becomes an exciting aspect.

And as the temperature of the steam is getting beyond the 700 degree mark, that even becomes more exciting to augment it into the LP and the IP side of an existing steam turbine.

So having said that, the cost drivers, without that aspect, of course, is the steam system, itself. The parabolic apparatus where we've seen some improvements in the cost, and you'll see the developments there. I think the learning effect of that technology of the parabolic apparatus has been an exciting improvement.

And, of course, significant land acquisition is one of the other drivers. And people need not to forget that there's a fixed and a variable O&M to the parabolic trough system.

And here you can see, as opposed to some of the other data that is in front of you, we've actually got tangible evidence to say that we've seen a trend down in the actual costs for these systems.

A lot of that comes from the aspects I

mentioned with the mechanical mechanisms. And also the fact that when we see a trend down like this, it's based on actual cost data that we've seen in the market.

Solar PV is very interesting, as well, from a -- this is one of the early renewable technologies that doesn't result in a spinning generator. And that and storage, I think, are the only things that generate electricity without turning a turbine.

But, of course, everyone's familiar with the flat-plate photovoltaic systems, either in a silicon substrate or in the (inaudible) technology. And there's some exciting developments, of course, in that area; none of which are commercial yet. Particularly in the collector systems in making the solar cells far more effective in taking angle radiation and converting it.

Those developments have not yet seen a commercial availability yet, but the low efficiency cells are certainly deployable.

Again, we looked at projects around the world. In Spain there's a number of the PV installations. We, of course, have installations in the U.S., as well.

And based on the data that we've collected, we also determined a kind of a size, anything over 20 megawatts, as a kind of a unit size, mainly driven by some of the electrical conversion apparatus required to do the dc-to-ac conversion.

But obviously size is only limited by the real estate. So the real cost drivers that we saw, of course, is the PV module costs, which are all over the map. We're seeing that's something that will change going forward. Significant changes in the production capacity is also driving the costs.

And then new manufacturing capacity, when available, will significantly change costs. And, of course, land acquisition. And there is a fixed O&M cost, as well, with PV.

So, again, this is based on data that we've seen. We've seen a significant trend down. And I think this is one of the things we mentioned right at the beginning that it's a moving target as technology, manufacturing capacity and the political environment changes. We'll see more and more changes in these cost projections.

With that, and the fact that I have not a good voice, I'm going to pass you to Chip.

MR. O'DONNELL: The next technology that we'll evaluate and present is wind. Basically in terms of California leading the nation in wind technology deployment over time, the technology is fairly well established. It's basically the same as the windmills in Holland of yesteryear.

The kinetic energy that's contained within the air stream, the wind air stream, turns a wind turbine. And I think some of the more important technology developments is the use of aircraft and gas turbine aerodynamic technology into the design of the turbines, themselves.

Not just in terms of the ability of increasing blade pitch or the length of each blade, but also in terms of the aerodynamic profile of those blades to improve efficiency and also to improve specific power output.

So, over the last ten years or so we've seen a substantial improvement and substantial technology upgrades that we've already experienced in the learning curve in terms of wind turbine technology.

Then that spinning turbine also drives a gear box which ends up driving a generator, producing dc power that is then ported to an inverter to produce ac power.

There are some wind turbines now that are not using gear boxes for power generation. But the vast majority of commercially available wind turbine technologies today do use gear boxes for power conversion.

As we looked at onshore wind the primary areas that we looked at were class 3, category 3, category 4 wind speeds. We looked at overall a 50 megawatt wind development. And typically those are comprised of windfarms that consist from 1.5 to 2.5 megawatt turbines. Typically around 80 meter towers.

In the future, as we've talked about before, the integration of aerodynamic technology from the aircraft engine and the aviation industry will continue in evolution towards larger rotors and turbine sizes and also tower heights.

The thing that we look at in terms of our configurations are that there are opportunities not only for repowering existing sites with new technology, as we've already seen in California and has been going on for some time, but also the development of the continued onshore wind sites.

PRESIDING MEMBER BYRON: Mr. O'Donnell,

MR. O'DONNELL: Yes, sir.

PRESIDING MEMBER BYRON: -- how big can they get? I mean, you can only -- structurally you can only make them so big, and my understanding is that we're approaching, you know, the tip speed on the blades is approaching supersonic now. So what is the limiting factor? How big can we get?

MR. O'DONNELL: There are a couple of limiting factors that I have seen and our research team has seen in terms of the available data.

The first thing is you're absolutely correct. Tip speeds go from subsonic to transonic into the area of mach 1. There are considerable issues around blade design.

And I think that is the reason that companies like General Electric, for example, have actually ported engineers over from the gas turbine side of their business, over to the wind side, especially in terms of blade aerodynamic modeling.

Because the aircraft engine industry has dealt with transonic blade speeds for about 15 to 20 years now, in military engines. And they've taken that technology base and they have moved it over to the design of wind blades for turbines.

I think, as well, a larger aspect around this, and I think why our research team sees the curve leveling off, as you also opined, is the reason around mechanical stresses on the nacel structures, themselves, and the gear boxes.

One of the things that our research team has seen in our research on wind is that the operational performance of wind turbines can be highly variable.

And one of the issues around ongoing reliability issues with turbines are in the area of gear box connection. You have varying stresses that hit the gearbox, and that could impact the overall capacity factor and reliability of the wind turbine units.

And so I think that is probably one of the lesser known aspects of the wind industry today, is the ongoing long-term reliability of wind turbines.

And I think the data that we have seen so far in our research is showing that, I think you're absolutely correct, that today we're seeing a leveling off. Where we would expect to see a continuing economy of scale from just an opinion standpoint, what we're actually seeing is that those technology curves tend to be leveling off right now.

PRESIDING MEMBER BYRON: So what is it, 3.5 megawatts, 4 megawatts?

MR. O'DONNELL: I think the upper eschelon is probably in the 4 megawatt range. I don't think right now we're going to push into anything above that. And I think it would take not only a continued evolution in aerodynamic technology, but also an evolution of materials technology.

PRESIDING MEMBER BYRON: Okay. Well, we shouldn't underestimate the technology. Everybody that's made those kinds of -- guesses before have been wrong on other technologies, so we're probably wrong here, too.

MR. O'DONNELL: That's correct. Looking at the overall cost drivers. The first cost driver for wind energy onshore is the turbine cost, itself.

The secondary cost driver is making sure that the turbines are reliable in service. And, again, that speaks to some of the operational issues that the industry has seen over the last several years, as turbines get bigger, as projects get bigger.

Not to mention the fact that maintaining a wind turbine is not an easy challenge. They tend to be high-risk. The turbine maintenance technicians are typically up in the air, in the nacel. And so maintenance of a gear box at 80 meters high tends to be more expensive than something on the ground.

The continuing aspects of permitting and site selection for wind and the access to transmission are other cost drivers that are currently seen by our research team in terms of overall wind development, as well as the costs of land acquisition.

The slide projection that you see here in terms of the cost trajectory is something that, as we started our research, has promoted a large degree of discussion within our research team. And I'd like to point out that in terms of our findings we don't believe that these projections are necessarily final.

What we do want to do in the workshop today is explain some of the methodology and the data that has produced this curve. But we reiterate that in terms of a cost curve that escalates over time quite substantially.

The reason for that is that our existing data searches in terms of cost showed a phenomenon over the last three to four years that I think is fairly familiar to people in the energy industry. And that is that the wind turbine industry reached its capacity actually several years ago.

Vestas, for example, in 2007, was sold out for a period of two years. They had greater than a two-year backlog in their manufacturing capability for wind turbines.

And so one of the things that happened as we looked at the historical data in terms of cost trajectories was that we started to see year-on-year escalations of 6 percent and sometimes greater.

We see all of that due to several things. One was the increasing cost of raw materials for manufacture of wind turbines. The second area was in terms of manufacturing capacity constraints that still actually continue to this day.

One of the things that our research team is doing, as we look at this, is that, you know, the projections based on the data are striking. However, we believe that there are market mechanisms that are underway, and will continue to be underway, that will mitigate and/or change that. And that is currently the focus of our research in wind.

So we wanted to present this to you based on what the current data is telling us, but also what our experience is telling us. And our experience is telling us that this is not something that we believe is sustainable, or else frankly there won't be a wind industry in about ten years. I think that's plain to see from the curve.

The larger issue is being able to validate the supply and demand, specifically in the United States, in terms of turbine capacity versus growth in the industry. And that is where our research is currently focused as we prepare the interim report.

As we look at offshore wind potential I think there have been some exciting developments primarily in Europe, and certainly in the United States. The Cape Wind Project off of Massachusetts is something that's current. The state of New Jersey has also opened up offshore wind for exploration, at least.

And I think in terms of our view, for category wind speeds, category 5 and greater, offshore wind also holds promise in terms of California's energy future. And that's one of the reasons why we looked at the offshore wind technology.

I think one of the keys in terms of offshore wind is that the ability to generate more electricity at higher capacity factors is certainly a driver around the development of offshore wind.

More consistent winds, and more consistent winds over time, also bode well for offshore wind as a technology.

The other issue is that looking at issues around height, offshore wind allows you to develop larger blade pitches and extract more of the energy out of the wind resource offshore than sometimes can happen because of offshore. And part of that is there's no structural interference from the environment. You've got open water.

One of the things that the research team has direct experience in, I spent some time over in Ireland with Eddie O'Connor, who at the time was the chief executive officer of Airtricity, LLC. And Airtricity and GE developed the Arklow Bank Project off of the East Irish Sea.

And one of the issues, I think, in developing that project was the difficulty in being able to put together foundations and support structures for the offshore turbines.

And I think one of the issues that comes into play as we look at technology implementation of offshore, the Irish Sea off of the Dublin coast where the Arklow Project is based, is actually fairly shallow water, 30 to 50 meters deep. And even there it was quite a challenge for both Airtricity engineers and GE engineers to put together the type of support structures and foundations required.

I think the problem compounds itself in a geometric fashion as you go to deeper water. Not dissimilar to the way the oil and gas industry has had to move from shallow water wells in the Gulf of Mexico to deep water wells, the technology cost tends to escalate geometrically.

I think that's one of the things we see as a key cost driver in terms of offshore wind technology development. It's not necessarily the wind turbines, it's the siting and the foundations that will sustain that project for a long period of time that tend to be highly variable in terms of the cost. It's do-able. These things are, as we've seen in the oil and gas industry, it can be done. The larger issue is looking at the stresses that are applied to a 100-plus meter tower with high wind speeds that you're looking at.

And quite a bit of stress ends up getting developed at the seabed floor where the foundations are.

And so that tends to be, I think, one of the key variations, the key variables, the key cost drivers as we look at offshore wind. I don't think it's a technology base in terms of the wind turbines, themselves. It's the actual getting the turbines in place and stable and with good support.

So, as we've looked at offshore wind, we've talked about foundations, the turbine costs. Reliability and maintenance will be heavily influenced by the distance offshore and the depth of the water that the turbines are placed in.

Permitting and site selection would continue to be not only a driver in terms of cost, but I think also in terms of long-term energy policy in the state, in terms of how offshore wind is looked at and potentially realized.

And then ultimately lease and transmission costs are cost drivers there.

One of the interesting things that we've seen, and I think Gerry Braun talked about it quite well in his presentation, is the difference between assumed capacity factor and actual capacity factor.

And I think as the state and the California Energy Commission looks at implementing offshore wind, as well as other technologies, offshore wind certainly is an area where we find a discrepancy between assumed capacity factor and actual capacity factor that I think will be critical in terms of the technology adoption for renewables.

One of the things you'll notice, you may not be able to see very well here, but the net capacity factor that we've assumed for offshore wind is 22 percent, 22 percent.

That's a substantial difference, as we'll point out later, from the 2007 IEPR study. And it's based on looking at actual plants in service in California, and data that we were able to find with our research team, that show that the actual realized capacity factor for wind in California is around 22 percent, versus 28 percent or higher, as we've seen elsewhere.

And so I think from a realization standpoint when you think about, you know, developers coming in to develop new projects for utilities, one of the key things obviously is what will the investment return.

And I think the variation that happens in capacity factor for both onshore and offshore wind is something that we will need to look closely at, not just as a research team, but also as a combined task as the cost of generation study moves forward.

And, again, one of the things you see here is the cost trajectory going up and, as we've explained before, there are market fundamentals that we think are shorter term that are influencing this based on the data that we have.

And we're looking at the longer term supply/demand balances for the draft report and the final report, as well.

PRESIDING MEMBER BYRON: Again, you show this curve starting around 2018. The Cape Wind Project, I believe, has been under development already for six years. They would probably dispute that this is out into 2018. Also, these are the highest costs that we've seen on any of the other generation technologies thus far in your presentation.

MR. O'DONNELL: That's correct. That's correct. I think part of that is, I think you're absolutely correct in terms of the time realized. Can a project be realized in six years.

I think some of the specific aspects with Cape Wind go to the amount of political resistance that that project has received over a period of time.

And my own development background tells me that some of that is not only based on policy and interest groups, things like that, stakeholder intervention, but also I think also the way that development process took place.

The initial announcement of Cape Wind in

Massachusetts was a very heavy-handed "we're going to do this". And I would suggest that that time was lengthened perhaps because a more collaborative approach was not necessarily taken at the beginning.

And so when that happens interest groups can galvanize and positions can be taken and compromise can be hard to achieve.

I think, you know, based on other industry experiences that six years could be do-able, depending on the right regulatory policy climate, as well as good interactions between utilities, private developers and the other constituents involved.

No doubt that that's a complicated, offshore wind development is a complicated issue. I would simply look at the Arklow Project off of the Irish coast as an example of how quickly it can be done, in contrast. And perhaps six years is not necessarily a bad middle ground. But I would agree that there's a lot of fungibility in how quickly it can be accomplished.

Looking at wave and ocean energy extraction, I think this is something that has been a topic in terms of renewable energy for quite some time. I remember beginning my career over 20 years ago, and one of the first projects I had to look at was a fixed-point bobbing installation for wind energy in the Ohio River in Cincinnati.

And so I look at ocean wave technology as something that continues to evolve and has difficulty, I think, coming into commercial operation. But nonetheless, has technical and commercial promise.

Basically wave energy is taking the kinetic energy of the ocean through wave action, and taking that and converting it into useful electric power. And there a couple of ways to do that.

One is through a point absorber, which is like a buoy that moves up and down and the kinetic energy of the ocean tends to power a generator.

The second is an oscillating water column where you basically have the, basically a chamber that's in a column of water, and the water column moves up and down based on the oscillation of the wave. What that does is it acts as a piston and drives basically a turbine generator.

I think some of the other opportunities for ocean wave is the overtopping where basically you have a support structure, the waves come over top, and basically fill a reservoir. A low-head turbine is installed in the reservoir, so as water drains out of the penstock, it basically flows through the turbine, producing power. And then you've got attenuation, as well.

So here are photographs of those. I think one of the key things in terms of looking at the cost of wave energy extraction is they are multiple technologies, and highly variable, highly variable in terms of cost and in terms of application.

We're looking at here overnight costs from $2500 to almost $7000 in the CEC study of 2007. And you're looking at a wide range of variation in terms of equipment and facilities costs.

One of the things that we see in terms of wave technology is the turbine cost and site development costs are primarily the largest issues in terms of overall cost for implementation.

And, as such, there are not very many -- any commercialized examples of this type of ocean wave technology that are there. We're anticipating, by 2018 there will be more of a drive toward commercialization. There is some funding in the industry that's driving that forward.

Once that happens then how reliable will those technologies be. That, we see, is another cost driver. And then the same issues as with offshore permitting and site selection and transmission are going to be issues in terms of ocean wave.

The larger issue that we also see is the large variation in energy that could be produced from ocean wave technologies As low as 4 megawatts to roughly 90 megawatts in terms of scale.

I suspect, in terms of overall technology, that we would expect to see rapid change in these numbers as time goes forward, as we look at the next biennial and the next biennial because there is an awful lot of commercial research going on to commercialize these technologies. So, we would expect to see changes in the profile over time.

Looking at the overall costs, again

there is an escalation upward in terms of time, I think primarily due to the site development and technology costs. That we don't necessarily anticipate seeing a learning curve in terms of the number of projects.

And part of that is, as we've looked, there are four different types of ocean wave technologies that are being commercialized right now. And when you look at the overall scope of developing projects, not necessarily looking for everyone to be jumping in similar to the wind industry, but more of a piecemeal approach. And that doesn't bode well from a scale economy standpoint.

The next option, and one of the options that I think is gaining a significant amount of commercial momentum, is coal-fired, integrated gasification combined-cycle technologies.

And the first implementation of coal-based IGCC was done through Synergy and PSI Energy back in 1995 under a Department of Energy advanced technology demonstrative project. And that's the Wabash River Cogasification Plant, where coal is gasified using a Texaco-based process gasifier; and then installed into a GE turbine as a first proof of demonstration, proof of concept back in 1995.

The nice part about that project is that project is still operating today. And so the technology demonstrator that first happened in 1995 continues to be robust more than 15 years later. And the technology, itself, is gaining significant momentum.

As gasification processes improve, and as the ability for gas turbine manufacturers to take synthetic gas, gasified from coal, and reliably process it into a gas turbine combined cycle.

Basically the scale of the technology is roughly 300 megawatts. And what that represents is a single train, typically a GE Frame F type of turbine. And we are assuming, based on our research, that that would be a single train, single turbine unit, based on what we see in terms of the current technology that's being deployed right now. Versus other combined cycle plants where you might see a two-on-one configuration, two gas turbines, one steam turbine.

What we're seeing more and more of, and what we're seeing actually in commercialized plants today, is a one-on-one scenario where you have one gas turbine and one steam turbine in the combined cycle unit. Which roughly gets to a plant sized around 300 megawatts.

One of the things that happens in the gasification is the coal is partially oxidized and produces synthetic gas. And the combustible components of that are CO and hydrogen.

You also have some greenhouse gases in terms of CO_2, but the CO_2 production potential for integrated gasification combined cycle is much less than that from burning coal separately.

And part of that is the reactor where you get the syngas will be of a much higher efficiency than by burning coal, for example, in a pulverized coal unit where you have differences in more incomplete combustion overall.

One of the things that happens and is a key aspect of the technology is the hot gas cleanup of the synthetic gas, because modern day gas turbines are highly sensitive in terms of contaminants introduced into the combustion stream. And so hot gas cleanup is a key element of the gasification technology.

What you see here is a manifestation of

one of the more current technology applications of coal-based integrated gas combined cycle, and that is Tampa Electric's integrated gas combined cycle plant.

There is also another plant that will be the second plant that Synergy, now Duke Energy, is doing at Edwardsport, Indiana, which is a complete repowering of an existing coal-fired central station power plant.

And so what they're doing is they're retrofitting the old pulverized coal plant with an integrated gasification combined cycle unit, and using part of the existing bottoming steam cycle from the original coal plant as a part of the combined cycle apparatus.

And so what you're seeing today in commercial embodiment of IGCC technology is you're seeing not just greenfield sites that are under development, such as the Tampa Electric Station, but also repowering and retrofitting of old coal-fired units and reusing some of the turbine technology that already exists there to lower capital and operating costs.

One of the nice things about integrated gasification combined cycle is the ability of the gasifier to burn and combust fuels of varying quality and varying types. Not just biomass, as Kevin remarked about before, but also fuels as varied as petroleum coke and coal, as well. And coal, at varying types and qualities. From eastern coal through Power River Basin western coal.

The basic issue in the past around IGCC adoption has been high capital costs. You not only have the overall cost of combined cycle gas-fired power plant, but then you have basically a process reactor on top of that, which is the gasifier. And then all of the fuel handling that has to take place for coal fuel handling.

So all of those put together has been a factor in terms of the decision over the past ten years to adopt incrementally the IGCC technology.

But I think some of the market trends that are driving IGCC today are, one, the reactor costs have been lowered as manufacturing economies have been achieved, and as process knowledge has improved.

The reliability of gasifiers has improved. This particular Tampa Electric IGCC has had a continuous run of the gasifier for about

2700 hours, which set a new record. In the past you would expect to see a much higher amount of gasifier trips that require restarts of the unit, or cofiring on natural gas.

Today what we're seeing is we're seeing the reactors much more reliable, and much more dependable in terms of cost trajectory.

Cost drivers, as we mentioned, are, you know, strongly suggestive around the fuel gasification process, as one of the key cost drivers. It drives costs not only from a first-cost perspective in terms of the addition of that versus a combined cycle gas-fired unit, but also in terms of the ongoing operational reliability of the plant, itself.

And so looking at the overall look at integrated gasification combined cycle, the continuing reduction of costs for the gasifier and the reactor will be a key to the continued adoption and large-scale adoption of the technology.

That, along with carbon regulation will also be a significant noncost driver around the technology. IGCC lends itself to significant abilities to capture carbon versus other technologies.

One of the things that you see in terms of the cost trajectories from high to low is average cost of 22.50 per kilowatt is significantly higher than that of a normal gas-fired combined cycle plant. But also relatively cost neutral and even cost advantageous when it comes to other renewable energy technologies.

And I think especially as carbon constraints come into our world over time, these economics will be tilted even more in favor of coal-based IGCC technology.

One of the other things that you see is you see the spread of costs. And why the spread? I think the first aspect is on the high side issues around siting and issues around gas cleanup and environmental regulations that are required, you know, for the successful permitting, depending on site location, and depending on fuel type.

The low side of the equation goes to options and abilities to repower existing coal-fired units, or existing central station units with IGCC technology.

So the variation in terms of low to high cost that we see is based on the technology-specific applications that are present within the IGCC world, from retrofit of existing technologies, to a normal greenfield installation, to a greenfield installation with much higher air cleanup or siting restrictions.

And then to finalize our technology review Kevin will present on nuclear.

MR. SULLIVAN: I must admit the sequence was not by design that we come to the cleanest technology last.

Having said that, I'm not sure if we have our expert online, but if we do have any questions we do have an expert who put together this analysis on the nuclear for us.

We basically looked at multiple different technologies in the nuclear side. And as you're aware, they are primarily boiling water reactors and pressurized water reactors.

But the most predominant in the selection based on criteria that we looked at was picking up the AP-1000, which is really a active/passive, approximately 1000 megawatt nuclear unit. And that is actually a Westinghouse technology based on PWR.

It is one of the most prolific, if you

like, technologies in the sense of licensing, in the sense of the Chinese market, which is also moving ahead with it. And the number of applications that have been looked at here in the United States, around about 12.

And I know, I think, in this audience we have a lot of people who have cut their teeth on nuclear. So I'm sure there is a lot of opinions on different technology.

But being a home-grown technology to the U.S., we selected this technology. And we've also found that while the AP-1000 was initially designed at a lower megawatt rate, we're seeing around about 1100 megawatt electric capacity coming out of this compact unit.

I should also just say that I think putting nuclear into this analysis is very valuable because it gives you a benchmark to look at the other renewable technologies against.

So the design, the typical plant design is a two-loop PWR, basically with a 60-year design life. It is also a first-generation three-plus design certification; and has actually been through the NRC design and certification process.

There are currently four units being

built in China. And I think around about 12 applications here in the U.S.

I mentioned the capacity, and you know, the improvements in the actual steam turbines that resulted in capacity increases, so we could quite substantially see a 1200 megawatt unit being developed as the steam turbine technology improves. On the primary side, I think that technology is pretty reliable and stable.

The interesting aspect, when we looked at the cost drivers, is we all know that fuel costs is one of the most attractive aspects of nuclear, but their licensing costs, although it only shows a 1 percent of the total cost drivers here, it is certainly a significant cost and an inhibitor to the start of these projects.

The other big cost is the actual cycle to construct. And the typical delays that you have in such a construction. So plant construction is actually a significant driver, mainly because of the period to construct, and the variations in actual plant versus actual costs.

Waste and decommissioning was also an important factor that the study team had to take into account, that there is a requirement to include into the cost and the operating costs, a decommissioning factor. So that is also a key driver, you can see by the cost factors here. Decommissioning can be up to 20 percent of the overall cost driver over the period for a nuclear plant.

Current costs range between a low side of around about 2300 up to a high side of 4600. This is quite in line with some of the previous numbers. I think a lot of these numbers can be validated quite easily because of the license applications that have been made. And the performance of companies that have actually tried to initiate construction of plants.

The average protection, I think, is a realistic one of around about 3000. And we see that in some of the plants going forward.

The proof is going to be in completing a plant, and then doing the analysis of what it really costs.

Covered the nuclear side of it. I think the other section, we thought to open up a discussion we would just do some comparisons between what happened in the 2007 IEPR versus what we see in some of the updates here.

And, again, we've got a couple of typos in here. We'll see if you guys can spot that. But, we took the geothermal flash and we said, let's have a look at the -- we noticed that the same size was looked at in 2007.

We see, of course, an increase in the pricing from the 2006 data to the 2009. And we see a reduced capacity factor from geothermal flash based on the capacity factor actuals that come from plants that we've studied.

The next one --

PRESIDING MEMBER BYRON: Just before you go on, the annual output degradation that you're looking at there, is that due to depletion of the steam field? Is that primarily --

MR. SULLIVAN: Yes, yes.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. SULLIVAN: Yeah, again, based on the plants that we've studied, we saw that happening.

On the parabolic trough analysis we chose a 50 megawatt unit versus the 63.5. But on average that's comparable.

The interesting aspect there is the annual output degradation has actually turned out to be .5 versus the .2. Again, based on the amount of plants that we've studied that have been actually commissioned.

I don't think the overnight costs, you know, reflect the learning effect that we've seen happen in solar parabolic technology.

And then we took a third one, which was basically the wind onshore analysis comparison. And looked at the 50 megawatt unit. And you can see that, you know, given the 2009 numbers versus the 2006, in overnight costs there's been very similar numbers.

In the O&M costs factoring in the capacity factors you can see the huge difference in our average capacity factor analysis for onshore wind at 22 percent versus, I suppose, a predictable plant capacity factor of 34 percent. And that obviously makes a huge difference to the cost of generation, levelized cost of generation.

PRESIDING MEMBER BYRON: What's taking place there between the two reports on the O&M costs, the fixed O&M costs in the 07 IEPR goes to zero in the 09, and then there's virtually the reverse effect for the variable.

MR. O'DONNELL: I think that could be

due to the treatment and the look between two research teams.

The way we looked at operation and maintenance for onshore wind is that the primary area of maintenance for wind turbine, most of the inverter and the power transformation equipment is solid state and steady. There's very little maintenance component that goes into that once it's operational.

The larger aspects are the rotating equipment pieces that are primarily contained within the nacel, blades, blade pitch apparatus, the gear box, the fluidic components, the hydraulic components that are in the nacel, itself, of the wind turbine.

And the way we analyzed that is that that function, that maintenance function can be highly correlated to the turning of the wind turbine, which is proportional to the megawatt hours produced.

And so in terms of looking at the maintenance component, I think it may have been simply a difference in treatment and analysis of maintenance costing.

PRESIDING MEMBER BYRON: Well, now,

since you're acting like you're done, --

(Laughter.)

PRESIDING MEMBER BYRON: You've provided three examples of comparison reports, what's your general conclusion? Either you put these three up because they represent some substantial difference in those particular areas? Because they represent relatively little difference?

I'd like to just understand how we progress.

MR. O'DONNELL: We actually presented those three because they provided probably stark contrasts between the 2007 IEPR and the 2009 IEPR.

One of our tasks in task one was to look at several documents that were done as a result in support of the 2007 IEPR process. Including work that was done by a company on prior generation costs.

In general we found that they were done quite well. The amount of research is thorough, the look at the technologies was substantial, not just from a technology perspective or commercial embodiment perspective, but in looking at how to implement those technologies.

The areas where we saw a difference

were, in some ways, a function of market changes over the last two years. Primarily in the solar technology arena. There's been substantial difference, and substantial experience effects that we've seen in the solar technology world.

I think in terms of other technologies, it may have been just a difference in experience base in terms of our, you know, certainly in our research we were able to, for several renewable technologies pull in the current state of the art that's happening in Europe, for example.

And wind, certainly, is one of those aspects where there are technology and project advances that are going on in Europe that aren't necessarily happening in North America at this time. But are moving in that direction.

So, I think, in general, we highlighted those three, Commissioner Byron, simply to highlight some of the contrasting elements of our study and to point out some of the reasons why,.

PRESIDING MEMBER BYRON: A couple other thoughts came up, if I could just pursue these briefly with you.

I'm forgetting one right now, but the other one that comes to mind was although these are generation technologies that we're evaluating, was there any thought to whether or not we should have also considered storage technologies in our analysis?

MR. SULLIVAN: I really do like that question. We really believe that that is a open discussion and something that the team came up very often. When you're dealing with capacity factors, there is low and off-point generation that happens with solar or wind.

We recognize that the viability of a lot of this technology is reliant upon some kind of storage technology. And as a result, I think you've seen some developments in the area of battery storage, which is very attractive. And even a small percentage of megawatts, as a total installed base for a windfarm to have a battery storage capability of the level of 20 percent of the total farm can change the capacity factor significantly. And, of course, the cost of generation of that windfarm.

So we really believe that's an important aspect that still needs to be discussed and analyzed.

PRESIDING MEMBER BYRON: Yeah, because

with generation, we never quite know where to put. And so we look for analysis. I would be interested in seeing that in future reports. So I'm speaking to staff really here, I think.

And, in fact, maybe Mr. Alvarado wants to speak to this, as well, why it wasn't included here or if he's thinking about including it in the future.

MR. ALVARADO: I understand that there are other programs in the PIER group that is actually evaluating storage opportunities. And I believe there was a workshop just the other day on that subject.

Although I do think that the capacity that they're talking about storage now is fairly small at current levels. Unless you're talking about pump storage opportunities.

PRESIDING MEMBER BYRON: Oh, well, that's going to change.

MR. ALVARADO: And --

PRESIDING MEMBER BYRON: All right, well, let me ask one other question to make sure I understand how to interpret this. All these projections figures that you've shown here, that were on the last page of each of the technologies, generation technologies, I just want to make sure how to interpret these.

Most show two figures -- I'm sorry, two lines, the installed cost -- well, they're both installed costs. I thought I saw installed and construction. No? Instant costs and installed costs. Sorry, it was so small I couldn't read it.

I just want to make sure I understand how to interpret that. You're not giving a range of values necessarily, those are two different -- those represent two different costs, correct?

MR. O'DONNELL: That is correct. That is correct. The instant cost, the instant cost would be the cost to instantaneously or overnight realize that plant. If you could build that plant in one day, what would that cost be.

So that would primarily be the present day sum of all of the components of that plant to be commercially realized.

The installed cost is the cost of installing that plant given normal commercial development conditions, whether it be utility, a public utility, publicly owned utility, municipal or merchant.

And that looks at a couple of things.

It looks at the development process and it also looks at the time-based nature of construction.

PRESIDING MEMBER BYRON: So why didn't you develop a range of costs? Why did you pick a discrete value that everybody could argue whether or not is correct?

MR. O'DONNELL: In some cases, in some cases as we looked at this as a research team, the commercial embodiment of the technology represents one scale. And one scale in terms of the commercial realization of the project takes a finite duration of time that is either commercially known or commercially available in the data.

So you can look at the time duration that it takes from initial project launch to project realization saying, I know there were several technologies, for example, that have a construction embodiment within the first year. So if you were to be a private developer or a utility and you make a go-decision on that technology, you could realistically expect to have that technology implemented within that current year. And so the installed cost basically will be the same as an overnight cost.

Contrast that, for example, with a nuclear project where you're looking at construction costs that would likely to into a four- or five-year construction cycle.

And so along the way, with that longer term construction cycle, you have, for example, construction interest or allowance for funds used during construction on the utility side. That would all have to be baked into and implemented into the final installed cost, which makes that cost larger.

And so that's the primary commercial difference that we see. Kevin.

MR. SULLIVAN: To address your question, actually we picked the average, and there is a high end and there's a low end. And what we put on the graphic was really the average.

And we still have more work to do on that with the data and where we are at the moment in the analysis. But we will have a range for you that could really depict the slide that Al or Gerry showed right at the beginning. That will show you the range of that technology from low end to high end.

PRESIDING MEMBER BYRON: Very good.

Thank you.

I very much appreciate this presentation, and it took a long time to work through it, but very good work and analysis.

Are we going to open up for public comment now and questions?

MS. KOROSEC: Yeah, I think it's time to hear from the folks here in the room, so if you'd like to speak just go ahead and come up to the podium, identify yourself for the court reporter.

MR. BLATTACHARYA: My name is Shan Blattacharya; I'm a retired executive from PG&E. Not much to do so I just turn up here to listen to you guys.

This was a very good presentation, by the way. And a couple of questions that I have, they may be directed to KEMA or to the staff, I'm not sure which way it's going to go, but first question is dispatchability.

As we encroach into the 15 percent capacity margin, some of the nondispatchable units are going to be stranded asset at the time of peak loads. So there's a cost associated with that. And that cost has to be addressed, in coming up with the total cost of generation.

The second question I have is not a question, it's really a suggestion, is on a hydro facility I guess KEMA has mentioned that there are opportunity for upgrading the hydro facility.

Having operated PG&E's hydro facility for several years I do know there is opportunity for 10 to 15 percent capacity upgrade, generation upgrade, in many of these facilities, with more power electronic systems installed, runner upgrades and all that.

I was really pleased to hear that that's a focus you guys are going to make in your IEPR. But, on top of it, what I would like to see addressed here is converting some of this hydro facility into the dual purpose. Storage, pump storage, and run-of-the-river generation.

Because a lot of these facilities have the flexibility. We, in California, are really blessed with certain hydro facility that can be converted into pump storage facilities. And that is going to help the dispatchability of a lot of the wind generation that's going to come down the pike.

So I just don't see how you cannot take that into consideration when you're filling out your new -- when you're completing your new IEPR.

Next item is I have a concern here on the wind. Maybe it's already been addressed by KEMA, and I think Commissioner Byron has raised it, there are several major structural issues industry has been coping with with respect to increasing the capacity of this windmill. (inaudible) happens to be one of those companies that's struggling with.

My question is with those technical uncertainty in place, are we addressing the cost appropriately. That means are we looking at a depreciation cost -- depreciation time appropriately. Especially for IEPR, as you start to change the depreciation the cost will be affected big-time.

And O&M costs, I believe KEMA has already addressed that. That needs to be addressed.

The fifth item is on the geothermal cost. Having lived through some of the geothermal plant in my past life, I didn't see any mention of waste disposal costs for the geothermal plant. They are not insignificant when it comes to decommissioning some of these plants.

So, you need to address that just like how you addressed the decommissioning costs of a nuclear plant, with some percentage. You need to bring that up so that it stays in the list of the cost drivers for geothermal.

Next I --

PRESIDING MEMBER BYRON: Mr. Blattacharya, what's the waste? Is it from the byproducts from the steam, or the actual plant, itself?

MR. BLATTACHARYA: It's the byproduct of steam.

PRESIDING MEMBER BYRON: Okay.

MR. BLATTACHARYA: That you cannot pump back. It's a substantial, you know, some of these sites are Superfund sites.

Next one is nuclear. Again, I think again someone already addressed that. I did not see the AFUEC cost addressed in the nuclear. Which is substantial, which could be almost 70, 80 percent of the instant cost, depending on, you know, which state you are in, and what kind of --

MS. KOROSEC: Could you repeat the cost?

MR. BLATTACHARYA: AFUEC. This is, you know, the cost of, what do they call that --

allowance for fund under construction -- under construction.

(Parties speaking simultaneously.)

PRESIDING MEMBER BYRON: Particularly when the construction takes eight to 12 years.

MR. BLATTACHARYA: It's really cost of construction, financial cost of construction.

And the last, but not the least, this is what I have for Commissioner Byron, I have made this recommendation to your predecessor, as well. This is not a very easy task, but I think we are getting to a point we need to address this.

And that is the possible portfolio mix to meet the renewable generation goal that we are aiming at, that means to hit the 20 percent renewable generation, what will be a portfolio mix.

There'll be a suite of mixes, but we're going to start looking at that suite of mixes and the corresponding cost, you know, the weighted average generation cost.

Are we looking at 30 cents a kilowatt hour or 50 cents a kilowatt hour to meet the goal that we are going towards? I think that's an important factor that we need to start showing it in our IEPR. With all these costs available now, I think we should be able to do that.

This will be the first time we will see that. And I think California is always in the leading edge of this kind of, you know, major ambition. And I think we've got to start showing our citizens what that cost will be to hit our renewable goals.

Thank you.

PRESIDING MEMBER BYRON: I have a couple questions for you. Thank you --

(Laughter.)

PRESIDING MEMBER BYRON: -- for the recommendations. The one, you know, realizing in your prior role as VP of strategic planning at PG&E, the conversion of hydro, or I should say the upgrading of hydro in considering pump storage, had you considered that while you were at PG&E?

MR. BLATTACHARYA: Yes. I know of three sites. And that same thing applies for other utilities and irrigation districts, as well. And DWR got sites, too.

PRESIDING MEMBER BYRON: And so why hasn't PG&E done it? Well, at least during your tenure?

MR. BLATTACHARYA: It was not necessary. Pump storage costs money. And that can be only --

PRESIDING MEMBER BYRON: Very good answer.

MR. BLATTACHARYA: That could be --

(Laughter.)

MR. BLATTACHARYA: -- only supported when the dispatchability becomes an issue.

PRESIDING MEMBER BYRON: Mr. Blattacharya, it's very nice of you to come, because I can remember years ago when you were at PG&E and you would meet with this customer and listen --

MR. BLATTACHARYA: Yes.

PRESIDING MEMBER BYRON: -- to my concerns and all my problems that I was dealing with and help me to provide solutions, and I very much appreciate your coming here in your retired capacity to give us the benefits of your expertise and make these kinds of recommendations. We'll take them very seriously.

MR. BLATTACHARYA: Thank you.

PRESIDING MEMBER BYRON: Thank you.

MR. ALVARADO: Commissioner, I could probably at least address a few of the points that were brought up regarding like stranded costs as well as identifying a portfolio mix of different renewable technologies that could be added to the system.

We are engaged in a number of different studies to, on one side, evaluate what set of renewables could be built to meet a 33 percent target. And we will be developing several different resource plans to identify whether it's going to be heavily wind, solar-based, or if there's any other alternative mixes.

And once we have these different scenarios for renewable portfolios, we will attempt to build any additional resources, generation resources, that might be required to maintain reliability or a target planning reserve margin.

I think once we have built these resource plans and engage in some simulation studies, we could at least identify, you know, how some of these other conventional plants might be performing, to note what their capacity factors. You know, I think that's one part of the puzzle I think you're really questioning.

And if we take a few steps further then

we can start examining associated costs. I'm not saying that we're ready, at this point, but the information we're gathering from this workshop is, again, one of those building blocks that will lead us down that path to identify those issues.

PRESIDING MEMBER BYRON: Yes. Thank you, Mr. Alvarado. You remind me that this, and I should have said this earlier, this is one of the key aspects that we're considering in this year's IEPR is the integration of large, high-percentage renewables.

And so there's a number of elements that will come together through the course of these workshops and the analysis that the staff will be doing. We hope to address a number of these issues, the ones that Mr. Blattacharya mentioned, as well as a number of others on how we're going to get to 33 percent renewables and beyond.

MS. tenHOPE: Suzanne, could you help us? Isn't that next workshop June 29 that will have some assessment of the cost of 33 percent?

MS. KOROSEC: I don't believe we'll have a cost assessment; we'll have an assessment of the other cost estimates that have been done, and discuss some of the inputs and assumptions that were used in coming up with those costs.

MR. O'DONNELL: From a KEMA perspective, and Mr. Blattacharya has some very good comments, and there are some things that we can address, as well, for the benefit of all.

The first comment that was made was around dispatchability and the 15 percent capacity margin being undermined, and the ability of units to be dispatched.

That actually happened in the mid 1990s in PJM during a winter peak. And I think that's an important comment to know the terms of the overall cost of generation study, because in the mid 1990s during a winter snowstorm what PJM found was that a substantial number of peaking units were on the books as being ready to fire, and being unable to fire.

And that led to a whole new round of reliability measures being taken in PJM to demonstrate reliability. And I think that comment is certainly germane, even today, when we look at tightened capacity margins over time.

PRESIDING MEMBER BYRON: I just want to make sure I understood. I thought what Mr. Blattacharya meant was that the planning reserve margins, is that correct? Am I --

MR. O'DONNELL: That's exactly correct, and --

PRESIDING MEMBER BYRON: All right.

MR. O'DONNELL: -- but those planning reserve margins are all based on units in the supply curve that are assumed operable no matter what. And that have significant reliability.

And what was found in terms of PJM incident in the mid 1990s was that units that were on the books and counted on to be a part of that reserve margin requirement were unable to fulfill that requirement. And so I think that bodes well in terms of looking at reliability of the generation fleet.

The second issue that we would like to comment on, based on the question, was around wind, and Mr. Blattacharya's concern about wind energy. And the several major structural issues that apply.

And I think that goes into the earlier dialogue around storage technologies and storage issues. Because one of the things that we've seen in terms of our analysis of wind in North America and Europe is the ability to levelize generation within a control area, and be able to monitor that within an electrical control area.

And so a lot of this goes into the historical argument about the intermittency of wind. And what that really does for an operational utility or a control area, an ISO, is it provides a significant amount of stress on the system where you're asking fossil units, gas-fired, combined cycle or simple cycle units, or even diesel peakers, to be able to respond on a moment's notice.

And what can happen in a control area is that oftentimes the fossil-based generation cannot necessarily respond quickly enough to meet the needs of the wind generation.

And so we thought that was a significant comment, as well, in terms of -- and I think this points to the ongoing use of storage in wind technology.

In terms of geothermal, the waste disposal costs and byproducts, we are taking that as an action item for our research team. We think that is something that would be important for us to look at, and we will do so.

And in terms of AFUEC, that's something

where we will look at the numbers, as well. But I have a feeling that we already have included AFUEC in there. We will verify that as a part of the comments in the return. Thank you.

PRESIDING MEMBER BYRON: That would be important. I tend to agree with Mr. Blattacharya, I don't think they're in there, but we'd like to know that, if they are.

MR. O'DONNELL: And we will verify that, sir. Thank you.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. ALVARADO: Yes, we're open for any other questions in the audience, and later we will open up questions to folks that might be listening on WebEx.

MR. TOWNLEY: Thank you. Dave Townley with Infinia Corporation. A request and then a couple clarification questions on the solar data that's here.

The request is a followup of the Commissioner's request -- or question earlier, regarding greenhouse gas sensitivities. And certainly if we could do that in this process to begin to at least look at a range of potential costs, greenhouse costs, and see the sensitivities of some of these technologies to that, would be very insightful.

Question on solar, specifically PV. Certainly I think you already caught the dollar-per-kilowatt -- dollar-per-megawatt piece, but it says that it's a tracker, single axis tracker. And yet in the presentation, itself, it shows pictures of fixed panel and talks about fixed panel. Is this single axis tracker? Is it fixed panel? Is it crystalline -- so, one question there.

And then would you comment, you show a very good graph that solar -- does in keeping track of the retail module pricing. And the current pricing shown here is dollar-per-watt dc, when adjusted for ac, it's above your installed cost. So the panel cost, retail panel cost, is above the cost your show as installed.

So the implication being that I guess the developers cost of that panel is so discounted that it accounts for the land cost, the inverter cost, the wiring, all those other costs that make up. If you could comment on that, as well?

Thank you for the opportunity for

questions.

MR. ALVARADO: Gentlemen, do you care to respond to some of these questions?

MR. O'DONNELL: On the solar technologies, the solar technology that was used was a single axis tracker and not a fixed panel.

In terms of technologies, the research team is looking at both crystalline and thin film. And part of that is the amazing amount of research that's been done primarily around thin film technologies starting in Japan and then moving into North America.

In terms of the current pricing and the solar -- reports, one of the things that I think we will do is we will revisit those just to be sure.

One of the things that we found in the research in solar data is there's a substantial amount of variation in the cost data that's being provided in the industry. And some of that goes from, you know, not just the installed costs and the cost decline of the modules both in Europe and Asia and in North America, but also in terms of the overall installed costs.

And I think one of the things that we

found, as a team, is that there was a substantial variation in the cost numbers. And those cost number variations were actually in the range of $400 to $500 per kW installed. Which may account for some of the things that you have illustrated in the questions to us.

So I think it's a good question for us to explore, and I'm certainly happy to do that. The one thing I would mention is that there's a substantial amount of variation in the published literature and the market data that we have.

Thank you.

MR. SHEARS: Good morning, Commissioner Byron, I'm John Shears with the Center for Energy Efficiency and Renewable Technologies. I'm standing in for Danielle Mills, who's our, who's our, you know, utility issues.

I just want to echo the previous speakers' emphasis that we also support exploring a greater reflection of comment on carbon policy in this analysis. We think that now we're in this AB-32 post scoping plan world, that that would be very valuable to examine the implications of carbon pricing on the technologies.

And just also had some clarifying

questions. Unfortunately, we didn't have a lot of time to go over all the presentation slides that were posted yesterday. Just wanted to check with the consultants, it appears that transmission costs were attributed to wind power projects. So rather than that being looked at as an overall system benefit, or ratepayer benefit, the transmission costs were actually attributed directly to the windfarm projects.

So I'd like to get a clarification on whether that is a unique driver attributed to at least onshore projects.

And then, again, reflective of carbon policy if, indeed, the wind is being attributed with other resource access costs that come with new transmission, then on the flip side we're looking at IGCC ultimately for carbon capture and sequestration, we end up with a resource access issue for sequestration, having associated costs with pipelines siting of the pipelines, et cetera.

So I'd just like some clarification on that. And also whether the Commission thinks that's also a valid point in terms of accessing and sequestering carbon and the resource areas available for that.

And then unfortunately April 23rd is a very rapid turnaround time on comments. We're planning on submitting some written comments, but it doesn't provide us with a lot of time to consult with our renewable affiliates on a lot of the cost assumptions in the work that the KEMA consultants have provided. So, we'll do our best. But it would -- we would have preferred to have a little more time to look at this and get back to the Commission.

And then just one observation on the offshore wind. My understanding is on the Cape Wind Project, which is the first major offshore wind project in the U.S., besides the complications that were noted that one of the large initial complications was, in fact, the issue of the state versus various federal agency jurisdictional issues had never been dealt with before until 2005, to clarify, at least whether the federal jurisdiction should lie.

So, hopefully going forward in wind power projects in California won't have to go through that territory again. Although, obviously, there will still be the community, you know, and the issues that come with those kinds of projects. So I just wanted to also add that observation.

Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Shears. Let's see if we can answer some of these questions. Would you like to go right ahead?

MR. O'DONNELL: In looking at the questions they're good ones. I think in terms of supporting climate and carbon policy, that's more of a question for the staff and the Commission, itself.

In terms of transmission costs that are associated with windpower projects, we absolutely, 100 percent agree with your statement that the transmission costs are highly variable.

As we understand this, the overall cost of generation study allows us to provide screening curves through Mr. Klein's work and the staff's model that will allow the California Energy Commission to make rational decisions around policy, around the future in terms of what's best for the state of California.

The issue at hand is kind of a complex one, and that's how do you value transmission costs for a site-specific development, such as onshore wind, or even offshore wind, and be able to take that in the aggregate and bring that down to a screening level.

And that's where the difficulty, I think, comes in. I think part of the question behind the question is transmission is obviously an issue in the wind industry because when you're looking at siting turbines on ridge lines and so forth, you generally are looking at new transmission construction and implementation.

What we have done is based on discussions with the staff in terms of looking at the overall transmission cost as sort of an overall aggregate cost, versus trying to understand a site-specific transmission component from the multitude of facilities that's around there. We've looked at that more as an average proxy base for transmission.

But we certainly understand and agree with the comment that the transmission costs are a highly site-specific component and driver of wind energy in the state of California, or anywhere else.

So I hope -- did I answer your question in that respect?

MR. SHEARS: Yeah, and this comes down to the philosophical perspective on whether, you know, it's fair to, you know, apply those costs to renewable resources when it's an overall system benefit.

And what we would like to see is, you know, the current system already has the benefit that it's linked up to the transmission system, and this is part of the challenge with large central station renewable versus traditional fossil where you can basically park the fossil plant wherever you deem fit, whereas you have to go where the renewable resource is.

And so what we would also like to see is maybe a comparison in the -- or at least a way to display that that cost is separated out from the analysis so that the power plant facility costs are directly comparable of the transmission having to necessarily be wrapped into the total numbers.

So, some way of parsing that so we can have a discussion about that facility, the differences in philosophical perspective.

MR. O'DONNELL: Transmission neutral.

MR. SHEARS: Right.

MR. O'DONNELL: Mr. Klein may have a

perspective, so I'll turn the microphone to him.

MR. KLEIN: Thank you. I'd like to clarify this that the transmission costs we're talking about are not the system upgrades, but the umbilical cord from the generating plant to what it takes to connect.

And the reason why we're focused somewhat on transmission costs, or for that matter any costs, is when we get a question from somebody, they say, well, how much does this cost. My first answer always says, well, it depends. What are you talking about. And one of the questions is how long will your transmission line be.

And this is why in this effort we're going to concentrate on having high low values. We'll have nominal average values, but we'll have high and low values. So when somebody is trying to compare one technology from another, they can see that there may be some overlap there in costs. And that they have to actually get into the details to make that decision instead of just taking an average value that they've typically looked at and jump to a conclusion of, you know, that's clearly the cheapest.

MR. SHEARS: Right. I understand that that's necessary, but at the same time, you know, we think when we're comparing power plants against power plants, just like to be able to see the numbers sort of separated out as, you know, the phrase transmission neutral.

Is there a way to do that, so you have those numbers available that you're talking about, so we can make, you know, -- we have technical staff that are working on these issues, as well, with the Energy Commission. So, we're aware of that. So, am I being clear on what I'm asking or am I missing the point?

PRESIDING MEMBER BYRON: Yes, I think you're being clear. And going back to the original question, I think the only place that I saw transmission costs built into the analysis that -- I'm sorry, the presentations you gave, was in the wind costs, correct, both onshore and offshore.

MR. KLEIN: Well, this is a question that I have actually that I haven't had a chance to ask this question to KEMA. But the original instructions were that all technologies would have associated transmission costs, that what was required to connect that technology to the existing system.

And whether, in each case, they've actually included those costs, I haven't had a chance to discuss that with them. And also they have been rushing, so maybe some of their data isn't as complete as they would like to have it.

PRESIDING MEMBER BYRON: Let's see if we can pin that down now.

MR. KLEIN: Yeah.

PRESIDING MEMBER BYRON: Can we get a sense? Is it only in the wind, or is there transmission costs associated with all the technologies in the analysis.

MR. O'DONNELL: There are transmission costs that are currently associated with all of the technologies installed. And I think they're fairly level across the spectrum.

And part of the issue is the transmission for any resource is highly site-specific. And so we have, I think we have some additional work to do in the transmission components.

PRESIDING MEMBER BYRON: This is the problem with using an average number. There's a lot of variability because locationally dependent.

MR. O'DONNELL: That's correct.

PRESIDING MEMBER BYRON: Mr. Shears is up again.

MR. SHEARS: Right, so they're not, just to be consistent across the board. I guess it would be useful so that, you know, in the display in the text of this staff report, you know, that there's some display, somebody can show how that cost is separated out from the plant.

So we can look at it from all angles.

MR. O'DONNELL: And that's absolutely a part of the data templates that we're providing to the CEC and Mr. Klein's efforts, yes. So that is separable.

There was another question, I think, in terms of carbon policy. And I think at the moment the carbon policy costs are not necessarily in scope in terms of our work to date.

In terms of IGCC and carbon capture, we have specifically excluded carbon capture at the moment and sequestration technology from the scope of the IGCC analysis. And the primary reason isn't that it's not a part of the current discussion around IGCC. Because I think that's one of the prime benefits of IGCC.

What we're seeing a lot of in the marketplace today in terms of commercial embodiment is the construction of IGCC plants that are sequestration modifiable. In other words, that are being set up so that you can operate the plant as a traditional IGCC today, but will have the ability to do carbon capture in the future.

And I think one of the things that you pointed out quite well in your commentary that we also agree with, is that siting of pipelines for sequestration is a very huge issue there.

Our concern today, from a KEMA technical perspective, is that the carbon sequestration technology has not yet been commercially embodied to our knowledge. And so to try and opine on that for the purposes of the study would be quite difficult.

And then finally, on the offshore wind question with Cape Wind, absolutely correct that a primary stumbling block was the difference between federal and state jurisdictions. That has now been resolved.

Thank you.

PRESIDING MEMBER BYRON: Okay. There

were two other issues Mr. Shears brought up. I'd prefer that we not continue in a dialogue here. Really, we're trying to do public comment and get through our workshop.

So let me see if I can address your other two issues. One, with regard to IGCC meeting sequestering of carbon, there are a number of other generation technologies here that create carbon, including, as I've learned recently, flash geothermal creates a fair amount of CO2.

So, I think, again, given that we're talking about a cost of generation model, what we're interested in making sure that that model has the capability to include the cost of the carbon in doing the analysis. And I would assume that that cost of carbon would reflect, eventually reflect the cost of the capture and the sequestration that would be necessary in these high carbon outputs. Remember natural gas -- has as much carbon as an IGCC plant would, as well.

The second thing I believe you said that we haven't addressed was the comment period. And I was going to turn to staff and ask if there was any latitude on the comment period. Because we welcome good comments. And we're responsive to the public's schedule, as well as our own.

MR. ALVARADO: I think the week comment period is mostly driven to our own internal schedule. Once we've digested a lot of the comments we've had today, and take the results from the KEMA study, we will move into our next phase. And so that's pretty much what's driving at least our schedule here.

I mean we would definitely like to hear any comments. This project is not over. As we indicated, the next phase will be a workshop on July 22nd where we will then present not only the input of all the technologies, including the natural gas plants, but also the levelized cost results.

So I'd say that there is definitely further opportunity for any comments.

MR. SHEARS: I wasn't going to debate any further. I was just going to maybe ask if, given the uncertainty, you know, in terms of commercial readiness of CCS associated costs, whether it would seem reasonable to have the quality of consultants provided -- qualitative discussion of the issues, as they see this being related to the issues associated with making an

IGCC plant CCS capable.

PRESIDING MEMBER BYRON: Well, essentially what the cost range would be for --

MR. SHEARS: Yeah, --

PRESIDING MEMBER BYRON: -- carbon capture and sequestration?

MR. SHEARS: -- and the challenges that would be associated.

PRESIDING MEMBER BYRON: And that's going to be variable, as well, for the different generation technologies.

Well, you can certainly put that in your comments, please. And I'll ask staff to consider that.

Any other public comments?

MR. CAMPBELL: Good afternoon. My name is Matt Campbell and I'm with Sun Power. At Sun Power I manage our long-term levelized cost electricity model. And I manage our utility power plant products.

Just wanted to make a few comments on the dialogue today, and I'd say, by the way, excellent and very interesting report by KEMA. I think it's one of the best jobs I've seen of aggregating what is very difficult to gather data and put it in an objective format.

The points I'd like to make first are the rapid growth of photovoltaic power plants. This was alluded to, but I think it's happened even faster than some might think.

There's now over 3 gigawatts of photovoltaic power plants that have been constructed around the world. It's difficult to know the exact number, but at least 2 gigawatts was built in the last year in Spain, and the balance in Germany, and to a lesser extent in the United States.

In the process of scaling up to this gigawatt level the plants have become much larger. So, four years ago we built that largest power plant in the world, which was 10 megawatts. The largest is now 60 megawatts. And in a few years it could be well into the 100s, as we've seen in projects in California.

The other thing to note is the rapid decline in costs. So there was an unusual situation in the last two years where there was a global shortage of photovoltaic panels.

And it's been pointed out correctly that the panel cost is actually higher than -- or was higher than some of the power plant costs that were referenced in the report. And then that's true. In fact, panels were sold on the spot market over $5 per watt just a year ago. And now you can get a turnkey power plant for less than that.

So, there was an artificial supply/ demand imbalance, which is now cleared because of global macroeconomic changes, as well as a huge growth in the number of factories all around the world, both in polysilicon factories, as well as solar cell factories, --

PRESIDING MEMBER BYRON: That global macroeconomic change that you're referring to is the economic downturn we're all experiencing, correct?

(Laughter.)

MR. CAMPBELL: Correct. And, really, the biggest impact is that slowed project finance so there's a queue of projects that are waiting to be built. It's also affecting the wind industry. But because the projects aren't being finished, it creates an over-supply situation and a correction in the pricing.

But I think probably the biggest driver

is more factories coming online in secondary, the recession.

Some other interesting things to note is two scaling effects with the photovoltaics. One is in the size and the technology used in the factories. So the factories used to be 100 megawatts. Now they're scaling to 500 megawatts or a gigawatt.

So you get economies of scale that are similar to what you see in semiconductors or flat panel televisions, where the production cost goes down. And sometimes geometrically with the size of the factory.

The other is scale in the size of the power plant. So, it was only a few years ago in California all of our power plants, if you call them power plants, were a megawatt.

But what we've found is as you go from a megawatt to, like this year we're building a 25 megawatt in Florida for Florida Power and Light, it's actually much cheaper, and there's a scaling effect that we anticipated but it's actually proven to be better than we had anticipated.

And it's kind of obvious because you have fixed costs associated with mobilization, project management, purchasing power in the components. So clearly as you go from one megawatt to 250 megawatts it's a curve. And there's a need of a curve around 25 megawatts. So I think you guys are correct in your identified unit size that you get a big scale there.

And then a third point on scaling, as it relates to O&M, I think you should look at your O&M costs, because there is a scaling impact in that for the large power plant, for photovoltaics. The ratio of people to capacity goes down and you can have specialists full time on the site. So you get a big benefit there.

The next point I'd like to comment on is land and land use. So, I agree with the Commissioner, this is a huge issue. We're seeing it all around the world. And the issues are aesthetic, environmental, species; in Europe, archeological. So, you know, obviously the plants require a lot of land, and there is an impact.

And then you've got finite transmission, and then you've got finite buildable sites. And then you've got a strong desire to locate the site where there's a lot of resource.

So, as vast as the desert seems, when

you start applying constraints, it is more of an issue. And we're seeing land prices increase substantially. And to the point where it was immaterial in the past, it is material now. But not prohibitive.

The other point is on capacity factor. I think this is really important. Is the vast range of capacity factors that you can see from a photovoltaic plant.

So if you build the plant in Sacramento as opposed to the Mojave, you could have as much as a 50 percent delta incapacity factor, and then you apply technologies like tracing, those improve the capacity factor. So I encourage an evaluation of a range of capacity factors.

There's a nuance with capacity factor in that the design of the plant influences the capacity factor through your ratio of dc panels to ac, and how they're managed, whether they track, how their temperature performance is. So there are design issues that can cause a range of capacity factors.

The other thing in the evaluation it may be worth doing is addressing peak period capacity factors. So, you know, obviously with solar it correlates with peak demand, but, you know, in the summer period you can see capacity factors, say June, July, August, of up to 38 percent in the very good locations.

And during the period of say 1:00 to 8:00 in the afternoon, the peak capacity factors can be in excess of 70 percent with a tracking system. So, very good correlation with demand.

And then finally, I think, there's a predictability element as you evaluate renewables and the ability to deliver the capacity factor from year to year. And photovoltaics are quite good, on an annual basis, delivering capacity factor within a pretty tight spread based on weather.

And then lastly, I'd just like to bring up the issue of water. And although it doesn't today go into the economic model, maybe we need a placeholder for it, because clearly the different technologies have either a different consumption of water in the steam cycle, or they have some sort of external water impact in terms of impacting salinity of the ocean, if it's using ocean water for cooling; or in the temperature if you're using a river or a lake to cool your thermal power plant. So I think it's worth putting on the certainly qualitative assessment, if not the quantitative assessment.

PRESIDING MEMBER BYRON: Both of those kinds of cooling are going to be off the table for not just renewable power plants, but for any other kind of generation.

Thank you for your comments.

Please.

MS. HEDRICK: I'm Jennifer Hedrick. I work for Southern California Edison, where I'm a project manager. And I appreciated the comprehensive presentation today. It was very interesting. I look forward to the continuation of the study and participating in the future in making comments.

I just had a couple comments today, though. And the first one actually refers to the IGCC plant and the carbon capture and storage, and including the cost in the study.

I wasn't sure if it was in or out, and I appreciate the previous question because now I know that it's not included in there.

It's a potentially important factor in the overall cost of a plant. And the technology exists for enhanced oil recovery. And then the technology for gasification is used in many other ways than just to generate electricity.

So the ability to capture the CO2 also exists. So I'm wondering if you could piecemeal from these other industries a reasonable cost estimate.

And the reason I say that is I see real value in this information, not just now, but in the future. I appreciated the slides earlier which showed well, in 2003 these were the values. And here it is now. And I think those trends are going to be very important.

And with the technology like IGCC with CCS, I think it's important for us to be able to look at what we would expect to be a downward trend in these costs as more of these plants are built.

And it seems to be an important technology for us in the future because unlike the renewables, as we talked about earlier, that siting them requires transmission. There's a lot more openness for siting a plant like it's a baseload plant.

So we would expect it to potentially be

a very important part of the future portfolio. But we want to make sure that we capture all the costs we see now, so that we're able to realize the down trend as times goes on and we can see that trend.

So I offer that comment for your consideration.

The next one I wanted to talk about is actually the size of the plants that are listed in the study. I really appreciated the number of variables that have to be dealt with, and the megawatt capacity of the plant is just another one, but it's a very important one when it comes to cost.

And some of these technologies like geothermal, it must have been very difficult to pick 50 megawatts. But it could have a significant impact. I'm wondering if some of the technologies like geothermal you could have some type of a series of curves, or a variability, you know, to better include the 5 megawatt as a greater than 50 megawatt.

And then along that line, kind of in reference to the megawatts, I guess back to the IGCC plant, then, it was interesting that the size that was selected, 300 megawatts, is pretty indicative of the existing IGCC plants in the world. There are about 300 megawatts right now.

But I think the new ones are looking more at a larger size because of the potential of the technology. It's time to increase the size and, you know, because of all the good aspects they have, we can make them bigger, put them where there already is transmission. And so there's value in being able to do that.

So, I was curious about the selection of 300 megawatts, why not more like 600 megawatts? Like the Edwardsport plant is planning. And I think some other plants around the world are looking toward that bigger size.

It may, in fact, you know, it seems like this report is so comprehensive there are many ways it could be used in the future. And perhaps using something like 300 megawatts in this technology, and other technologies, could actually limit assessment of the size.

In other words, in looking at building a power plant of this type, if someone looks at this report and sees 300 megawatts, it may limit the thinking in going bigger to 600 megawatts. And that might be the right answer.

So I would just caution that it seems like we wouldn't want to limit development here by inadvertently down-sizing the size of the power plants.

So, thank you very much that we had a chance to make some comments today.

PRESIDING MEMBER BYRON: Thank you for your comments. I'm not sure that you really can respond to all of those right now. I mean I can appreciate the difficulties in taking a reasonable sized plant that you're going to do your analysis on. I think of nuclear, you know, if somebody were to build a nuclear plant they'd build two. And then your costs go out the window, as well there, too.

So they are good points, though, Ms. Hedrick. I'm not sure if you're looking for a response right now, but certainly I think these are points that we should consider in future generation --

MS. HEDRICK: I don't need a response right now, thank you.

PRESIDING MEMBER BYRON: Thank you.

Any other public comments?

MS. KOROSEC: Is there anyone on the phone that's interested in commenting? The lines are open for those on the phone if you'd like to make a comment.

MR. van AART: (inaudible).

PRESIDING MEMBER BYRON: Could you please identify yourself?

MR. van AART: Frans van Aart, KEMA.

PRESIDING MEMBER BYRON: Yes, we have a difficult reception with you. I hope we'll be able to understand you, but go right ahead.

MR. van AART: Okay. (Indiscernible.)

PRESIDING MEMBER BYRON: Yes, we can hear you.

MR. van AART: Okay. Concerning the (inaudible) of the IGCC plant, this one is based on the experiments (inaudible) worldwide with IGCC. I agree that there may be in the future a somewhat increase of scale, maybe with a maximum of 25 or 50 percent, but certainly not the 600 megawatt scale.

The limit is, in fact, in capacity of the gasifier and also the capacity of the gas turbine which is suitable for our syngas commercial.

MR. SPEAKER: (Indiscernible.)

PRESIDING MEMBER BYRON: Go ahead; there's just a little bit of noise on the phone line. You can proceed.

MR. van AART: Okay. When you want to go to a 600 megawatt that will certainly be a plant consisting of two gasifier lines and maybe also two gas turbines.

And for this study we elected to use a one-module approach.

PRESIDING MEMBER BYRON: Okay. I think I understand your comment. IGCC limited to the size of the gasifier, and therefore the 300 megawatt sizing isn't what you think to be a good size for this --

MR. van AART: Yeah.

PRESIDING MEMBER BYRON: -- analysis. Thank you for joining us.

MR. LOCHNER: Maybe another comment? My name is Karl-Heinz Lochner. I'm the consultant for the nuclear. And is for the question from the gentleman about does the AFUEC cost included. I checked it in the meantime. And my understanding was I think it's correct, this means that the financial cost of construction. I think this was the understanding.

And I checked this one, and this costs are included.

PRESIDING MEMBER BYRON: Very good. So, can you also tell us what duration construction time you assumed, as well?

MR. LOCHNER: Then the construction time is typical between seven and nine years.

PRESIDING MEMBER BYRON: Okay. Very good. Thank you for being able to close on this issue all the way from, I assume you're calling from Holland.

MR. LOCHNER: I'm from Germany --

PRESIDING MEMBER BYRON: Germany

(Laughter.)

PRESIDING MEMBER BYRON: All right, good; thank you.

MR. van AART: I'm calling from Holland, yes, from the Netherlands.

PRESIDING MEMBER BYRON: Thank you very much. It's a little late there, gentlemen.

Do we have any other commenters on the phone?

MR. van AART: (Indiscernible.)

PRESIDING MEMBER BYRON: Well, I think

we're very close to finishing here. If there's no other comments, can we go ahead and close.

I'd like to thank the staff; I'd like to thank all of you who attended here today. Very good presentations. Thank our contractor, as well, on this work. And particularly those who came here from the public that were willing to sit through this and learn with me, as well as make comments.

This will be very helpful to me and to my fellow Commissioner, Jim Boyd, on the IEPR Committee.

It is quarter to 1:00. I think it's time for everybody to go to lunch. Thank you, all.

(Whereupon, at 12:45 p.m., the Staff 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 Staff 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 11th day of May, 2009.

PETER PETTY