STATE OF CALIFORNIA - THE RESOURCES AGENCY
BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

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	)
Preparation of the 2013	)
Integrated Energy Policy Report	)
(2013 IEPR)	)

Cost of New Renewable and Fossil-Fueled Generation in California

California Energy Commission
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Reported by:
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STAFF

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Also Present (* Via WebEx)

Presenters

Richard McCann, Aspen Environmental

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*Myles O'Kelly, Itron

Public Comment

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George Taylor

Chase Kappel, Pathfinder Renewable Wind Energy and Zephyr Power Transmission.

INDEX

INDEX

P R O C E E D I N G S

MARCH 7, 2013 10:09 A.M.

COMMISSIONER MC ALLISTER: My name is Andrew McAllister, Commissioner at the Energy Commission and Lead Commissioner of the 2013 IEPR.

This is a staff workshop, but I wanted to just welcome everybody here. And I see there are lots of people online, which is great, so welcome to you all as well.

And so, I'm just going to run the proceedings here but I wanted to make sure everybody felt welcome. Presumably, we can tell you where the restrooms are, and where the egress is, and all that kind of stuff, so for those of you in the room.

We're really looking forward to -- this is, I believe, the third workshop we've had getting going on the 2013 IEPR. Lots of real great substance in this workshop and coming up in future ones, so far we've had some great conversations. We're really looking forward to putting this document together.

And Ivin and his team are a central part of that so, thanks Ivin for putting everything together.

And thank you all for coming. We're really looking forward to your input.

MR. RHYNE: Thank you, Commissioner McAllister.

Again, my name is Ivin Rhyne and welcome, everyone, to the 2013 Staff Workshop on the Cost of New Renewable and Fossil Fuel Generation in California.

Just a few housekeeping items before we begin. This workshop is being recorded.

And for those of you not familiar with the building, the closest restrooms are located just outside the double doors and to the left.

There's a snack bar on the second floor, under the white awning.

And lastly, in the event of an emergency and the building is evacuated, please follow the employees to the appropriate exits. We'll reconvene at Roosevelt Park, located diagonally across the street from this building.

Please proceed calmly and quickly, following employees whom you are meeting with, meaning the employees here in the room, to safely exit the building.

We're going to get started here and it's actually wonderful to see such a crowd for cost, which is typically a very technical and in some ways mundane topic but, obviously, germane to a lot of folks.

And this is a staff workshop. We're going to try and be somewhat informal.

The workshop, itself, we're going to kick off here with an introduction and get things rolling.

So, let's see, just give me a moment and we can. So, we've got several topics to cover. First of all, I want to talk just a moment about some of the key concepts. We're going to give you an overview of the project, itself, and then cover today's agenda as well.

First of all, the real question here that we're trying to answer or at least take an attempt at is how much does it cost to build new central station generation in California.

And my economist training gets to leap straight to the fore here and say it depends. It depends on a number of things, location, technology, the operational profile you're seeking, whether you want to just figure out what it costs to build it or how much does it cost to both build and operate.

The important piece here to understand is that the question of how much does it cost presupposes, to some extent, that you've decided which one you wish to build.

There's a lot of information we're going to share about a number of different technologies, their component cost today, and the pieces that go into what it costs to both own and operate those costs, but they do not form the whole basis for decisions on which investments are made.

So, when it comes to attempting to estimate costs for planning, first we have to figure out what those costs are in context.

First of all, this project is about understanding the cost to build and operate a central station power plant. It's an estimate of cost for generation portfolios for planning purposes. And to some extent it can be used to anticipate possible investment decisions.

But as I just said, it's not the only basis on which those investment decisions are made.

When we talk to people who actually bankroll these projects, the people who do the lending, they're often talking about how much is the revenue versus the cost for any particular projects.

And in this investors typically use a discounted stream of both costs and revenues.

In this case we're taking those costs, which often fluctuate over the life, and turning it into a single cost value. You can think of it similar to the way your mortgage is structured in the sense that if you are paying the principal and interest you could, perhaps, structure your loan so that you paid less and less every year as you got closer to paying it off.

But instead, you turn the entire loan, both principal and interest into a steady stream of payments that doesn’t change over the lifetime.

This is similar to what we’re doing here. We’re turning that potentially fluctuating cost into a stream of values. It results in the same lifetime cost as if we had allowed for each of the individual years to show those variations and it’s usually expressed as a cost per unit of energy.

So, it’s sometimes referred to as LCOE, levelized cost of energy, and it can be expressed, the units are often dollars per megawatt hour or cents per kilowatt hour.

So, the scope of this project is to understand and estimate the cost to build and operate new central station technologies over the next decade and we’re really focused here on likely technologies inside of California.

There are a number of studies, both national and regional, that estimate the cost to build, for example anywhere in the United States, for some of these technologies or, perhaps, anywhere in the Western United States, when we look at planning purposes for the Western Electricity Coordinating Council.

This project, related to the 2013 IEPR, is really focused on understanding what those technologies cost if they are built in California at some point over the next decade.

A caveat here is that there are a number of projects. We can look back at projects that were built last year, two years ago, five years ago. And while we attempt, as we'll talk about later on, to sample those projects, understand how much it did in fact cost to build them, those aren't the only ways to estimate what those costs will be in the future. And we'll talk about how we adjusted for that going forward.

We also took out a number of technologies from our 2009 report that were either in the development stage or were not considered likely to be built.

For example, California is not really in a position right now to -- it really hasn't expressed a preference, I should say, for building new nuclear power plants. Certainly, that's an option, but not really something that's very likely, and so we've removed the estimate of what a new power plant built in California costs.

As this project is something that we renew on a regular basis, we'll be constantly reevaluating which technologies are likely to be built and estimating those costs, as well.

Another important key and, really, one of the reasons why we’re having a workshop and not simply releasing a number of documents online and asking everyone to take pot shots at it, is that stakeholder feedback really is key. This is a discussion forum, an opportunity for us to really look at, talk about, and understand the elements and components that go into estimating these costs.

Now, there have been -- in 2011 the Energy Commission held a workshop where we asked some very key stakeholders to come in who, themselves, either use or build levelized cost and cost-estimate values and tell us, well, what could we do better? What have we been, perhaps, doing wrong, what are we doing right, those types of things.

Well, one of the really interesting pieces of feedback was, you know, it’s interesting to talk about the cost for any single developer, but what if -- what if we wanted to look at the system cost on a levelized basis for a new project?

For example, what if we wanted to build a new renewable plant that doesn’t operate 24 hours a day?

Well, if you’re a utility, you’re obligation is to serve 24 hours a day, not 8 hours a day. And so there would be some additional, perhaps, costs that we might want to think about under that scenario.

So, in looking at and scoping, working within budgets and limitations we decided in this iteration not to attempt to estimate that system-wide cost and simply stick with estimating what does it cost the owner of the plant to build and operate that over the cost.

One of the other things we did is we looked at, were asked to look at the debt service coverage ratio. This is an important financial indicator that tells those who lend money how much of that should come from borrowing and how much of that should come from equity.

And we were also asked to look at carbon and emissions costs.

One of the things we chose to do is kind of restructured the approach here and really focus on the component costs. We can talk about what that levelized cost or net mortgage payment really means, but until we talk about how many square feet the house is, and how many amenities, and what those cost as add-ons, a lot of people who might potentially use -- and, obviously, I’m speaking in analogy here. If we don’t talk about the cost for with and without duct firing, for example, in combined cycles, if we’re not talking about solar thermal with and without storage we lose some of those important discussions.

And so, we're really focusing on and discussing component cost.

The focus of new cost of generation is in the iteration, and we'd really like to investigate doing more of those system costs in a future iteration.

We added the flag in the model results to talk about this debt service coverage ratio, DSCR. It's not something that we built in as an automatic change or a fix, but it's something that if you run the model and it falls below a certain level of DSCR, something that we'll talk about a little bit later, that pops up.

And we've also included carbon costs in the model consistent with those put out at the February 19th workshop that was held here, talking about the possible scenarios that will be run in a kind of coordinated modeling effort between all of the different divisions here at the Energy Commission for the IEPR.

Other changes that we're talking about in 2013, we're evaluating ranges using a tool called Analytica, and we've got some experts here in the room who will be coming up and talking about that. It's really an important element in that we can build ranges based on a lot of different reasons.

We can push things to extremes and see how high in a once-in-a-lifetime type of scenario, or how low those costs might end up being. But, really, how do we understand what's likely?

We've also simplified the user interface so that those who end up actually using the model, rather than extracting the data from it, have an easier time. It's more straightforward. You go through and select "once" and push "execute" and it runs.

We've also improved the outputs, the immediate outputs that you'll see there on the front page of the model, itself.

And we've dealt with tax equity financing. This is an issue that Richard McCann, from Aspen Environmental, is going to be talking about. It actually becomes an important piece of how some of these renewable projects are financed and handled.

Finally, we would love to bore you with a number of tables and graphs, and just flood the screen with numbers, but sitting there in the room and perhaps at your desk somewhere, that can be very overwhelming and difficult to understand.

Really, the core of the cost work is about a set of numbers that we're talking through. And so, we've created a "Cost Data" handout that is available at the back of the room here, today, and it's also available online. So that those of you who want to take a look, really the meat of those pieces are contained there. And so you'll see several of those numbers reflected here today, as well as there will be a lot of material -- there is, I should say, a lot of material both in graphical and tabular form that will allow you to look through, really kind of dig in, understand and ask questions.

And, really, it's important that you do ask questions. Giving us feedback is really how we make this project better and so we really want to be at a point where we are able to incorporate that feedback, grow, improve, and do something that's really of value to you as stakeholders, to the Commissioners, and decision makers here in the State.

So, with that we've reached kind of the end of my opening comments and the overview.

We're going to launch right in to the first major section, which is to talk about the financial estimates and issues, some of this stuff that gets a little bit tricky, that DSCR stuff.

As well as after that we'll move into the renewable cost estimates and methods.

We're going to -- after each portion of the workshop, major portion I should say, we're going to pause and we're going to ask for public comment. So, our next really opportunity for public comment is going to come after the renewables cost estimates. So, if you have questions, other than just clarifying, feel free to hold onto those and after the renewable section we'll ask for that.

Then after renewables we're going to break for lunch, hopefully right around noon, and we're going to come back about one o'clock.

After that we'll move into talking about the fossil fuel type generation, natural gas.

And then we'll wrap up the day with discussions on the probabilistic approach using the Analytica tool and what that has helped us generate in terms of the ranges of potential levelized costs once you allow for the possible variations, and all of those component costs that we're going to spend the day talking about.

And so with that I'll turn over the podium to Rich McCann, from Aspen Environmental, and ask him to talk through the financing assumptions.

MR. MC CANN: Good morning. I'm Richard McCann. I'm with Aspen Environmental Group.

And I want to say this is all -- even though you'll hear a lot from me today, I'm actually just the front man for a lot of team effort which involved a lot of individuals and firms. And you'll hear from most of the firms that assisted us in this project.

The first one up is Bill Monsen, who's from MRW. He actually did most of the lion's work on this -- the lion's share on this particular financing section and he's available to answer questions on this when we get done with the section.

So, I'm just going to walk through the slides that we have and present to you the assumptions that we used based on the data we gathered for financial assumptions for the model.

So, first off I'm just going to walk through a brief introduction of what we've done with the model. I'm going to talk about the methodology for gathering and updating the data we had developed for the model.

I'm going to summarize the findings and highlights that we have for financing of renewables.

And then I'm going to do the same thing talking about the gas-fired power plants.

As you may well understand, the financial parameters are key for calculating a levelized cost of energy for each of the power plants, whether you have a five percent weighted cost of capital or a ten percent can make a big difference, particularly for capital-intensive types of technologies like the renewables.

Financing has become increasingly complex in response to tax policies and market conditions. There's the tax incentives that are offered by State and Federal government. They greatly influence the types of financial structures that these power plants are using.

And the market conditions have changed as both the end response to the financial crises of 2008 and to how power purchase agreements, and bids into the marketplace have changed.

In this particular model we relied much more on detailed survey and data collection than we did in previous versions of the model. We had used generalized financial assumptions, but we found that they were not particularly targeted for specific technologies, and that there were ranges that we were hearing about that we wanted to explore more. So, we created this new task of looking at, interacting more, much more with the financial community.

And then we now are able to enter financial parameters that now vary by technology for this reason.

The methodology that we used for gathering data from the various financial institutions, which Bill led that effort. They spoke with five different types of institutions that were geographically diverse, had different market focuses. And they all requested confidentiality so, to a large extent, we have masked it. As to the extent we can, we've masked their responses, but the findings are still quite useful.

We provided them a list of questions prior to calling them so that they had a better idea of what sort of issues we were interested in. And then we compiled the survey results to summarize those findings.

We then cross-checked the results with findings from other sources, such as NREL's finance tracking initiative, Bloomberg's data, and a series of webinars by Chadbourne and Parke that have information, as well, on financing trends.

And then we reviewed the publicly available PPAs from the PUC database to calculate average escalation rates for the power purchase prices which drive our merchant power plant, LCOEs.

The findings, the key findings and highlights that we had for all of these technologies, there were a number of interrelated assumptions on interest rates, leverage ratios, debt service coverage ratios, and the term or tenor of the debt.

The quality of project sponsors affected the type of financing that we saw. Of course, as the quality or the size, to a large extent, of the sponsored increased, the costs of debt would decrease.

There were questions about accepting merchant risk. That is, having your debt term run longer than the power purchase agreement. That was quite rare. Most of the time the power purchase agreement actually sets the horizon, the time horizon for the debt on the project.

And the size of the project can really influence financing costs. As the project size increases, the perception of risk also increases and in large part because it becomes a greater share of the portfolio of the individual financers.

And interesting result is that Japanese and Canadian banks are quite active in the U.S. market in financing these projects.

For renewables, the wind and solar projects are considered less risky than biomass and geothermal projects, and in large part because of the technology and fuel source risks that they perceive.

That biomass, for example, has a cost associated with the acquiring the biomass to burn in their boilers, that solar doesn't have, for example.

Lenders are structuring their debt to account for the technology risks of solar projects. One of the risks for solar projects is that the costs are dropping so rapidly for particular projects that the timing of when you sign your PPA and the construction period that you have for the project can actually present a risk for those solar projects.

Resource uncertainty can affect the financing costs, as well. So, they will typically use P99 or 99th percentile forecasts for setting their minimum one-year debt service coverage ratios.

This is particularly important for wind where the year-to-year variation in output can be rather significant.

And then tax credits are an increasingly important part of the financing packages for these projects. There’s not only the project sponsors who are investing in these, but they often turn to outside parties to invest in the tax -- gaming the tax credit returns, as well.

The tenor or term for the debt for renewable projects is getting much shorter as a result of bank balance sheet risk from long-term debt.

So, before the debt terms could be quite close to the length of the PPAs, which are 20 to 25 years, but for more recent debt, the debt tenors have been substantially shorter.

And there are other sources of long-term debt that may allow for hybrid structure. So, a project could have four or five different types of debt instruments that are actually financing the project.

So, the results from the survey, we find that we -- the way we incorporated this information, we started with the Board of Equalization Capitalization Study Model as the way of estimating the various financial parameters, using the information that we got from the survey.

We used the LIBOR swaps spreads as a proxy for the cost of debt. Bill, what's that -- LIBOR stands for London Interbank Overnight Rate. That's right. So, that's been in the news recently. that is something that has become of particular interest in the news at this point.

There's also the tax efficiency structuring for the equity, itself. And it's used to maximize the tax credits and other incentives.

In many of these cases, the project sponsors are firms that are not large enough to absorb all of the tax credits in the amount of time that's required, so they have to bring in other, larger institutions that can actually use the tax losses on their books, and they become partners in the projects for that reason.

Wind typically uses a partnership flip structure in their financing for tax efficiency. And other technologies typically use sales lease back structures, and that has to do with the types of tax credits they use and the amount of return -- the amount of revenue that they gain during the year compared to their annual costs.

The results of our survey, this gives you a quick overview of the types of information that we got; the debt service coverage ratios on an average basis for the tenor of the debt and the minimum one-year levels that are for each of the technologies, and the typical leverage on the projects that were reported by investors, along with the pricing over the LIBOR, and the typical tenors of terms of the debt by technology.

You can see that there's some ranges by the technologies. An interesting aspect is that the wind debt tenors are significantly longer than they are for the biomass and geothermal projects.

And you can see the relative risks that are perceived by investors in these projects.

Now, one of the interesting things that we also found out about this, in looking at this, that many of the debt term, debt instruments are interest-only debt repayment, with a large balloon payment at the end of the debt.

We didn't have much information on the projects -- on the debt financing of the projects after the end of this initial period, so I'm going to talk a little bit about how -- what we ended up doing is that we found -- used the assumptions for the project bonds in order -- which have, typically, a life that's similar to the length of the PPA, in order to do -- to model the financing of these renewable projects.

And so we made some adjustments based on that to these various costs that we found in the survey.

For gas-fired generation, we found that the debt costs were somewhat higher than for the renewables in large part. We think, or we were told to a certain extent that was because the projects are typically larger than the renewables projects that are being financed out there.

The tenors for the gas projects are typically also shorter than for the renewables and that, we understand, is likely due to differences in the terms for the PPAs. That is renewables often get 20- to 25-year PPAs, where the gas-fired PPAs are ten years or less.

And some of the lenders are willing to take a small amount of the merchant risk. That is taking on some of the debt load after the end of the PPA. And a portion of the project output may also be uncontracted and that they will take on some of that risk associated with that, as well.

So, for the gas-fired plants here's the results that we had in terms of the minimums and maximums on average, and minimum debt service coverage ratio, the amount of leverage that we see on these projects, and the pricing over LIBOR, along with the tenor of the debt.

In the financing by the investor-owned utilities and the public-owned utilities, we relied on the Board of Equalization Capitalization Study for models and inputs for the IOUs.

We derived ranges for the inputs into that model from WECC Utilities and National Data, and we applied this to all technologies on the assumption that the IOUs would invest in any of these projects out of its pool of entire investment capital.

For publicly-owned utilities, we assumed that they were 100 percent debt financed, and we typically used highly-rated public bond rates that were publicly available to input that into our model.

We took these findings and we applied them to the cost of generation model. We incorporated tax equity financing as an important component to the renewables.

This is a new feature since 2009 because in the

2009 model we were basically able to use the IRS Tax Grants as their financing mechanism for the tax credits. That's no longer available, so we've now incorporated much more detail about tax equity financing.

And there's a page in the model, if you look at it, a page, I believe, called "Renewables" that has the formulas for the way we handled the tax equity financing.

And then we reported the debt terms that don't cover the entire project life. But we decided to rely on the long-term project bonds in the renewable financing, to the extent possible, so that you will see debt terms that are longer than some of the ones that we have in this particular presentation.

Here are the financial parameters by cost case. So, we show the mid, high and cost case assumptions. You can take a look at these tables.

Where it says "Variable" in the table, those are technology-dependent assumptions and those are shown in this table, which has the equity share, the cost of equity for the different components of equity, tax and developer equity shares, and the debt with the cost of debt.

And then the weighted average cost of capital that's implied by each of these on the far right.

And with that, we're open for questions.

MR. HATTON: Hello, my name's Curt Hatton from PG&E. I was wondering what assumptions you made in terms of ITCs and PTCs going forward? Did you assume they continue at today's rates or did you assume changes, for example 2017, or what the assumption was?

MR. MC CANN: So, what we did in the model is we have three sets of assumptions that we use in the model, the low cost, the mid case cost, and the high cost case. And we have different ending assumptions for each one of these cases.

For example, in the high cost case, we assume that they end at the end of the legal time period. So, typically, around 2017 there was a change in the law, in December, which actually makes it so that it's the online date, not the -- or the date of initiation of construction, not the online date, so that extended the deadline for these projects in many cases. We have that change in there.

For the mid case, I can't remember if we ended -- I believe in the mid case we assumed the end of the -- again, the end of the tax credits at the legal deadline.

And for the low cost case, we assume that they extended on to the end of our time horizon, past 2022 for our model.

So, that was the kind of analysis that we did. You can run mixes of assumptions in the model in order to come up with different assumptions. That's one of the flexible things that you can do in the model.

Any more questions?

So, with that, we're going to move to discussing the solar technology cost development. And in doing this, we retained two firms to do the work. Previously, in previous cost-of-generation models we were hearing back that our assumptions and ranges that we were getting from the models were too narrow, in large part because we were reflecting the perspective of a single firm, rather than multiple firms.

So, we changed this approach in two ways, two important ways. The first being that we get the range of having two firms doing the work and the second one is that we relied much more on publicly available data, which also increased the range of estimates that we got.

And so I'm going to now turn this over to Karin Corfee, of Navigant, to do her presentation for how Navigant developed their costs.

And then, after that, I'm going to turn it over to Itron to do their presentation, as well. Myles O'Kelly from Itron will do that.

So, with that, I will turn it over to Karin.

MS. CORFEE: Hi. Can everybody hear me okay?

My name is Karin Corfee. I'm with Navigant Consulting and I'm based in San Francisco, California. And I'm pleased to be here today to present research findings on solar cost of generation or, more importantly, installed cost for solar.

Uh-oh, bear with us just for a moment, please.

All right, so apologize for the delay.

Navigant looked at, basically, PV system cost projections for crystalline systems with tracking, as well as fixed axis film systems. And then we also looked at CPS systems for parabolic trough, with and without storage, and for power tower with and without storage.

And the size ranges that we looked at were, for PV, 20 megawatt and 100 megawatt, and for both the crystalline with tracking and the fixed axis thin film.

And for parabolic trough we looked we looked at 250-megawatt systems, and for power towers, 100-megawatt systems.

So, now we're going to look at the PV system cost projects. And I do apologize for this.

But this is a graph that basically shows the cost trends for the ground-mounted crystalline PV arrays. On an installed basis, on a dollar-per-watt, peak watt DC. And as you can see, we're looking and we're projecting the cost to decline from $3.50 per peak watt to about $1.50 per peak watt in 2025.

The higher cost trends, which are depicted by the red lines, are the 20-megawatt system. And the lower trend lines are for the 100-megawatt system.

And this is our cost trends for the thin film, fixed axis systems, ground mounted, and this is 20-megawatt for the red and 100-megawatt for the blue.

And, you know, the cost for the thin film, fixed axis, are basically projected to be slightly lower, primarily due to the lack of tracking systems.

Now, how do we derive these? We looked at the various sources, it's very well-documented within this PowerPoint presentation at the very end, in the appendix.

But for the component prices we looked at SEPA price bulletins and, really, leveraged the most recent data that we could.

This is a key difference from the last time around that we did cost-of-generation research where we were constrained, we could only use published data and there was an inherent lag time in that, for obvious reasons, and it created problems primarily for solar PV because cost trends were declining so rapidly during that period of time.

So, I think we kind of adjusted our approach this time around and we were able to leverage more recent data.

From a capacity factor standpoint we used SAM modeling, which is an NREL-based model. And the tracking systems, we are projecting almost a 26 percent capacity factor, and for the fixed thin film systems about a 20 percent capacity factor and that's at a probability of 50.

The on-site transformer and transmission costs were derived from the IOU estimates and we netted out inflation in those estimates.

And then the low-cost projections were based on the SunShot DOE aggressive goals and then the high were based on an article by a fellow at NREL, by the name of Goodrich.

All right. So, this particular slide just depicts the relative cost of the various components and this is for both the high and the low, for both the 100-megawatt and the 20-megawatt systems.

And as you can see, the bulk of the price is due to modules and on-site transformer and transmission costs.

And next I'd just like to go on to the CSP price projects. And I do apologize for having to rotate these every time.

But as you can see, the parabolic trough costs are projected to decline much more slowly than PV costs. And again, just to remind you, the higher the blue lines are for the 100-megawatt systems and the red are for 250-megawatt systems.

And our assumptions are documented here, as well as in the back, at the appendix. But we really looked to the recent DOE loan guarantee projects for the bulk of our assumptions, as well as NREL, and Black and Veatch recent studies.

Capacity factors with storage we're looking at 43 percent, without storage we're looking at 27 percent. And this is California-specific research and I think that's important to note that all of our research really was looking, specifically, at the California marketplace.

We were assuming 10 hours of storage, using molten salts. And the maintenance projections we're using the SEGS plant and the study by Sandia National Labs.

So, for the power tower costs we -- basically, you know, they have much wider uncertainty bands and you can see that with storage and without storage -- obviously, when you have storage the costs are much higher.

And the costs associated with our research was really, again, looking at the DOE recent loan guarantee projects and we also look at NREL's SAM Model assumptions, and estimates to derive our costs.

The capacity factors for power tower were estimated to be 31 percent with storage, 40 percent without storage. And the component cost breakdowns, we looked and we leveraged studies done by NREL, and Black and Veatch, and Sandia on power tower technology road map.

Again, we modeled a 10-hour storage configuration. And the projections on the low side, we looked at various studies, and on the high side I can't recall right now, but I'd be happy to answer that question should anybody ask. And it's all very well documented in our research.

The cost breakdown, again, you'll see that with storage and without storage the field costs are a very large component of the total cost, as well as the indirect cost, including the contingency.

And that really concludes our research. But I will say that we do have, at the end of this slide deck, a very detailed synopsis of our data sources for each of the technologies, as well as the low, mid and high cost projections.

So, with that I'd just open it up to questions. And I should also say that I have -- you know, the folks that helped with this research are based -- I have Graham Stevens on the phone, he did the CSP research, he's based in Idaho, Jay Paidipati is based in Colorado, and then Dr. Shalom Goffri, who's based in our San Francisco office.

So, we're certainly available to answer any questions anybody might have, should you want to contact us directly. Our contact information is within the slide deck.

COMMISSIONER MC ALLISTER: Karin, so just a quick question. So, I was a little surprised that the storage costs for the CSP weren't bigger, which is a pleasant surprise, actually.

And I'm just kind of wondering if anybody on your team could comment on where that technology is at the moment and sort of what -- yeah, sort of how -- I mean, obviously, it adds value on the benefit side, particularly with capacity, and matching system loads, and all that. So, I'd be interested and maybe you could comment on that part of the CSP equation.

MS. CORFEE: Sure. Graham Stevens led the CSP-related research and so I'm going to defer to Graham, and he's on the phone, I understand. Can we unmute?

Graham, bear with us for just a moment. Graham, do you know which caller ID you are by any chance?

Oh, goodness.

MR. STEVENS: Can you hear me, Karin?

MS. CORFEE: Yeah, we can hear you, Graham.

COMMISSIONER MC ALLISTER: It looks like he's 27.

MS. CORFEE: Yeah, there you go.

MR. STEVENS: Sorry. The storage date came from the estimated costs in a number of the DOE loan guarantees, as much as possible. And then from, you know, a variety of studies.

And, obviously, storage costs are in flux and it's a very new technology, and it hasn't been firmed up, so we tried to capture sort of the variability associated with, you know, much higher potential costs in those high and low scenarios.

But as I said, you know, storage is not a -- you know, it is just on the verge of becoming commercial so those cost estimates are certainly less reliable at this point, until they get to be more commercial and well-founded.

COMMISSIONER MC ALLISTER: Okay, thanks.

MS. CORFEE: Are there any other questions?

All right, well, thank you very much.

MR. MC CANN: So with that I am now going to turn it over to Miles O'Kelly from Itron. Which, hopefully, this will work, I'm going to drag down this icon to Miles and now change the presenter, yes.

MR. O'KELLY: Hello, this is Miles O'Kelly. Can you hear me?

MR. MC CANN: Yes.

MR. O'KELLY: You can, okay, very good. and do you see my screen or are you seeing just the slides?

MR. MC CANN: We're just seeing the slides.

MR. O'KELLY: Great, okay. Let see if I can actually move it. It looks like I can, very good.

This is Miles O'Kelly with Stephan Barsun. We worked together on developing the costs for photovoltaic and concentrating solar power, or solar thermal, as you'll see it described here.

And Stephan is not available at the time, so I'll do this for you. The costs we have developed here, like Navigant, are for new plants and we forecasted installed costs going forward.

These are unit costs, dollar for megawatt of electric net output. And we developed low, mid and high cost outlooks through 2030.

This is all secondary research based on other studies, both academic and industry studies, and no primary research on costs. Many of the same sources that you just saw a moment ago from Karin's presentation were used in looking for costs.

These studies included currently operating and planned costs for plans now, as you have mentioned, forthcoming plants.

And in addition, then, the cost recognized the growth in the technology over time and the growth in installed plant capacity.

All of the costs also took into account two of California's siting, and in terms of levelized costs of energy the solar performance that would be typical for Southern California, primarily.

Among the primary sources here was, again the aggressive goals of the 2012 SunShot study. The Black and Veatch study, with NREL, was very valuable. And updated plant costs from EIA, and several other sources that we used to try to bring together as many perspectives on what the expectations were for costs going forward.

The commercial embodiments that we foresee in the future were -- or that were used, for that matter, in the different studies included large photovoltaic systems from 2 to 500 megawatts of capacity, modules fixed or modules tracking. The tracking, as mentioned, will increase the cost of the plant and, therefore, the unit cost.

It also includes increases to capacity factor, but does not add to the capacity, itself.

Likewise, in the concentrated solar thermal, commercial embodiments would range from 50 to 230 megawatt electric with single steam turbines driving those. They could include the troughs or towers, and it could include the thermal energy storage options where, like tracking on PV, the storage increases the cost and the capacity factor of the plant, but it does nothing to increase the capacity, itself.

So, the plants that we considered as the commercial embodiments going forward were 100 megawatts each for the photovoltaic, one fixed, one tracking.

The most operational projects currently are only in the 2- to 60-megawatt range, so that there are not many at this point that are operational at that 100-megawatt level.

Overall, worldwide, there are about 6,000 plants now, many in Europe, with capacities on the order of 60 to 100 megawatts.

And these planned plants that we included considered some that were, again, up to 500 megawatts, ten times larger than what we're seeing now.

And in terms of plant capacity, much of the total plant capacity, 10 percent of it, comes from these very large plants.

On the concentrating solar thermal technologies, we considered three different plants, two troughs, 150 and 200 megawatts, one without storage and one with six hours of storage, so it could operate at six hours at full capacity using that storage.

A third was the 230-megawatt tower plant and that would have 11 hours of storage.

Worldwide there are only about 50 trough plants operating and six tower plants that are commercially operating, so the numbers that we could reference from the studies were relatively small compared to photovoltaic systems.

And as Karin mentioned, thermal energy storage is something of a new advance for concentrating solar thermal. It's going to increase the cost, but it will lower the levelized costs because of the great increase of capacity factor that results.

The other assumption we have with these concentrating solar thermal is that there's no natural gas backup boiler, as actually exists in some cases of operating plants today.

As far as their performances for the fixed array photovoltaic systems, from the high-cost side we had a lower annual capacity factor of just 21 and on the low-cost side we had a better performing system at 25.3 capacity factor. Again, this would be Southern California, primarily, as our location.

The tracking array clearly does better with its capacity factor ranging from 27 on the high cost side, down to -- or up to 31.5 on the low cost side for performance.

For concentrating solar thermal, without storage, in the 20 to 29 percent annual capacity factor range, adding storage on the troughs raised that up substantially so, 41 percent on the high cost, 43 percent on the low cost range.

Tower is getting up even higher with 11 hours of storage, ranging up as high as 62 percent as an annual capacity factor.

These capacity factors we developed using the NREL's SAM model, System Advisory Model.

COMMISSIONER MC ALLISTER: Can I ask a question, quickly, on that? The range for the tower with greater storage, with 11 hours of storage, seems really wide.

What's the upper limit on that or what's the sort of thinking behind, or your understanding of why that range is large, and what the factors -- sort of how you get up to 62 percent, which is pretty phenomenal?

MR. O'KELLY: Oh, the idea there is that the 62 percent capacity factor is what might be allowed. Again, this is based on the secondary research from our studies that 62 percent could be reached with an 11-hour storage system based on the estimates from the System Advisory Model.

COMMISSIONER MC ALLISTER: Okay.

MR. O'KELLY: Now, if you ask me what are the total hours per day, I don't have that readily available. But clearly, if you look at this on a 24-hour basis, you're looking at a substantial part of the day.

But the models that -- or excuse me, the research that we considered in looking at these things, we had to actually develop 11 as our standard reference point. A number of the systems, and with cost, et cetera, had 14 hours, some had 9. It was important in putting together the numbers to take into account both the different levels of storage that might be used, as well as the different levels of solar field that would be appropriate for those levels of storage.

One of the important aspects and the difficult aspect in considering the subcomponents of concentrating solar thermal was recognizing that there are different solar field sizes that are chosen for different storage capacities.

So, across the different studies we came to a resolution of using 11 hours of storage, and I believe the solar field factor was 2.5, but I'd have to check back on that.

I hope that answers your question.

COMMISSIONER MC ALLISTER: Yeah -- no -- thanks. So, you're looking at this whole -- the field storage as a system and you would make -- in order to achieve 62 percent I'm understanding you would sort of make a different balance, presumably, based on really going for a higher capacity factor.

MR. O'KELLY: Yes, clearly, the 62 percent capacity factor would have the larger field that would be charging that storage system during the same hours that full capacity was being generated from a steam turbine.

COMMISSIONER MC ALLISTER: Great, thanks very much, that's good.

MR. O'KELLY: The other cost forecast key assumptions for PV -- or going forward the cost trajectories for modules and inverters would follow learning curves. This is generally the approach used in most of the studies, looking at learning curves in terms of aggregate capacity and the decline in cost that's associated with aggregate installed capacity.

The other assumption was that the aggressive goals in the SunShot study for balance of systems were optimistic, but not unreasonable. And the understanding there, too, was if their aggressive goals were reached early on that subsequent cost reductions would be rather small.

In looking now just at the PV plant, when we consider the rudimentary breakdown of cost components, they're the modules, power conditioning, inverters, balance of system, including non-inverter hardware, and non-hardware, and the other costs, soft costs and so forth.

Well, if we look at those, here for example you'll see in the year 2010 to 2011 the dominant component for the PV system cost is the module. And here you'll see, from left to right, two sets of comparison bars and that the module cost dropped substantially in just this short period. It's module costs and their costs going forward in the future that are largely driving down the cost of the PV plants.

The other costs, as you'll see other cost components here, they will change with time but, clearly, the lion's share is in the module and that also is where the lion's share of the decline is happening.

Here is an example of the learning curve for PV modules. And PV has not strictly adhered to these learning curves as cumulative installed capacity has gone up over time.

There was that period in the early 2000's when -- and you can see this in the black dots as they flatten out prior to the left of 2009, when module costs had gone up due to silicon shortages.

And now they have fallen down, you'll see in 2012, below the black learning curve that was developed based on the historical trends.

Our expectation is that module cost will continue to follow these learning curves, you know, going into 2030.

And while modules, the prices are now below the learning curve, again we believe that they will -- may continue that way but essentially follow the trend of the learning curve.

There could be corrections in the future, it's hard to foresee. But in large part, cumulative volumes will impact the -- fill that learning curve.

And on the low side the presumption is the low cost side -- or excuse me, the low growth side was just 10 percent per year in a cumulative installed capacity, 20 percent on the moderate after 2016, and 25 after 2016 for the high growth, again, impacting the slope of the learning curve.

It’s also important to consider, and this was important in determining what was the commercial embodiment of the capacity, that the scale economies impact PV plant unit costs. But if we look here at some costs over time -- excuse me, over accumulated capacities, as you increase the system size in the lower right-hand curve you’ll see that beyond about 20 megawatts to 100 megawatts the unit costs per plant don’t change substantially, so that there economies of scale begins to fall off in terms of its importance to the total plant cost, somewhere above 20 megawatts.

So, these are fixed costs forecasts for PV systems out to 2030, so at the high cost case over three and a half dollars per watt. And the low cost side starting just above $2,500 per kilowatt, falling down even below $1,000 per kilowatt by 2030 and again, this is on the low cost case.

And the mid-range you can see is between one and $1,500 per kilowatt.

The higher costs for the one-axis tracking array do not decline as swiftly on the high side. They do start out higher, reach down to $1,000 per kilowatt in 2030, on the low cost case, and this is largely with the aggressive goals of the SunShot Study that we believe are, at the same time, reasonable.

On the high side the costs do fall below $3,000 per kilowatt by 2030.

Looking now to concentrating solar thermal, the key assumptions there were that thermal energy storage increasingly will be adopted to improve the economic performance of the systems, and we have storage included in two of the commercial embodiments.

Solar field sizes, as I mentioned, are increased to be able to charge those thermal energy storage systems at the same time that the plant is actually generating at capacity, so it can use that storage in later hours.

So, several of the studies described, specifically, their future plants as using dry cooling. Again, this is increased cost, capital cost, but decreases operational costs in terms of water consumption in the future.

The individual plants would have individual steam turbines, as opposed to multiple steam turbines.

This also helps reduce the unit cost because of the declining costs of very large steam turbines, and no natural gas backup for boilers for the systems.

The subcomponents for concentrating solar thermal differed substantially from one study to the next and it was difficult to strictly compare costs from one study to the next because of where they would include, for example, the steam generation system, in the power block or not.

These components here are a higher level of aggregation, but the most important of these include the solar fields. For parabolic troughs, those are the linear reflectors that the pipes pass through. For the power systems it's the heliostats, the reflectors that focus the light atop the tower.

Key transfer fluid is another substantial cost. The power block, where the steam generation occurs in the power generation, thermal storage systems that balance this system, and then soft costs that include development, et cetera.

To bet a better idea of how these components weigh in on the total cost on this chart shows components and the levelized cost of energy. They apply, also, to the installed cost.

And you'll see that the solar field, in orange, in each case is a substantial portion of the largest portion of each of the levelized costs here.

Beginning in 2015 you'll see in the trough and tower where the introduction of thermal storage, in light blue, occurs. And going forward from 2015 to 2020 you'll see that the cost of thermal storage also comes down, along with the cost of the solar field, but the solar field remains a very large component of the cost.

Among the soft costs you'll see two, in the light green the indirect cost of construction and financing.

You'll see here that the thermal energy storage begins in 2015. Our commercial embodiments consider the storage as starting with our forecast period. And this graphic is from the SunShot study.

So, these are our installed costs for the tower with the thermal energy storage out to 2030, all beginning in the range between seven and ten thousand, about $8,500 per kw.

The decline begins to -- in 2020, a faster decline for the towers with storage, dropping down below $2,000 per kilowatt in 2030.

TES is short for thermal energy storage here.

If we look, now, to trough with storage they, too, are beginning up in the area of seven to over eight thousand dollars in 2010, and not having quite the decline that we see as for the towers after 2020.

But on the low cost side we do see a more rapid decline. This, again, makes use of the aggressive goals with the SunShot study.

And, finally, here are the troughs without storage. A much lower first cost, installed cost, in the $4,000 per kw range. Not so substantial a decline with time, relative to the others, but, again, you don't see the changes that are occurring here with the declining costs presumed for thermal energy storage.

And I'll take questions, if there are any.

MR. MC CANN: Well, Max Henrion's walking up to the podium to ask a question.

MR. HENRION: Yes, I'm Max Henrion from Lumina Decision Systems. And I have a question that I understand may be a little challenging, which is in thinking about the low, medium and high projections that you provide how extreme do you consider the low and high to be.

MR. O'KELLY: I believe I'm unmuted, but I'm not hearing anything in the background. So, if there are questions, I cannot hear them.

MR. MC CANN: Can you hear me?

MR. HENRION: Shall I repeat that question?

MR. SCHLOSBERG: Dave Schlosberg from Light Source. I'd actually wanted to ask a question from the Navigant folks, but I'll ask you the same question. What assumption are you making --

MR. MC CANN: Hold on just a second here, we've got cross-talking.

MR. HENRION: Let me know if you'd like me to repeat that question.

MR. MC CANN: Try, Max.

MR. HENRION: Okay, let me know, can you hear me, now?

MR. O'KELLY: I can hear you, yes. This is Miles.

MR. HENRION: Excellent, thanks so much. This is Max Henrion from Lumina Decision Systems. And I have a question which I understand may be a little bit challenging, which is in thinking about the low, medium and how projections how extreme do you consider the low and high? Are they sort of absolute ranges, or one in 99 percent, or 10 and 90 percent percentiles? You know, how would you think about them or is that a fair question?

MR. O'KELLY: I think that's a fair question, yes. And I would not consider them to be one in 99 percent. I would probably lean more toward the 90 and the 10 percent.

The low cost case clearly looks for technological advances and declining costs across the board, across many subcomponents. It's largely dependent, of course, upon the growth, the learning curves and the absolute growth in installed capacity, and so forth. Economic conditions may or may not allow for that, you know, between now and 2030.

So, on the low cost side not -- I wouldn't say that's a one percent change, but I would think there's a 10 percent chance.

The high cost, on the other hand, I would believe that's certainly more reasonable to hit, but what we're hoping for is something that's less expensive and so the value that it provides can occur.

So, I would say probably 10 and 90 on the short side.

MR. HENRION: Thank you.

MR. MC CANN: Just a second. I think David Schlosberg has a question. Yes, you're on now.

MR. SCHLOSBERG: I was asking, trying to ask the Navigant folks, but I think it's appropriate here, too. The assumptions are on the working fluid and if that working fluid in the tower for a CST tower is the same as the storage medium that can drive a lot of implications for cost, for configuration, and it’s not stated clearly in either of the presentations what the assumption is for the tower working fluid.

MR. O'KELLY: The difference -- I can -- unless Karin wants to jump in, I can speak to some degree to the various studies in considering potential changes in direct steam production, for example, as opposed to making -- in the tower making great use of transfer fluid.

There are different technologies, also potential for storage for going forward, and these would -- and also changes in the heat transfer fluid production and manufacturer, itself.

Well, that subcomponent and its changes over time, changes in costs over time were not addressed thoroughly across -- in any particular study. You’re right that the heat transfer fluid can become a substantial part of the cost. To a certain degree it is a consumable, and so it’s part of operation and maintenance cost.

But both in the tower and trough configurations the use of storage -- I have not specified here whether that will be the fluid or an exchange media, for example.

Whether -- how that makes a difference, I think in the future, will depend upon what technological advances take place with regard to using that route as opposed to a liquid storage system.

And maybe someone else from Navigant can comment on that, too. I'm not sure who their right person would be.

MR. MC CANN: Just a moment, Karin Corfee's coming to the mic.

MS. CORFEE: I would defer to Graham Stevens, who's on the line, who did RCSP research. Graham, do you want to comment on that?

They're trying to unmute you right now.

MR. STEVENS: How's that, can you hear me?

MS. CORFEE: Yeah.

MR. STEVENS: Okay, so with regards to the power tower, obviously, there are really not that many technologies that are in the marketplace. And so Navigant's kind of base case was against the DOE loan guarantees that are becoming commercial and coming online.

And then we just simply tried to capture the variability in configuration, you know, with heat exchanger fluid being one of them, storage being others. You know, dry cooling versus wet cooling, you know, that a large number of variables and potential configurations, especially in tower technology, and we tried to capture those variations within our relatively wide range of estimates on the high and the low side.

So, that's kind of the basis for Navigant's estimates.

MS. CORFEE: Thanks, Graham. Does that answer your question?

MR. SCHLOSBERG: It answers the question of how you developed your ranges and what this information means. I think, especially in the near term, some of the configuration assumptions and the cost assumptions are heavily reliant on what the plant is that you're thinking about. And depending on how you configure that plant it will drive a dollar per watt, it will drive an hour of storage, it will drive a lot here.

But I think to the point as you go out in time, the technology, as it develops, it's more uncertain where those cost reductions come from and you cannot be certain.

So, I think that having a band of ranges is not getting too focused on the specific technology as you go out in time that this is probably accurate.

MS. CORFEE: Yeah, I think you're absolutely right and thanks for the comment.

MR. MC CANN: Okay. A comment from the speaker.

MR. PIETRUSZKIEWICZ: Yes, my name's John Pietruszkiewicz from Black and Veatch. I have a question, I guess both to Navigant and Itron.

But the question goes to the methodology that was used to do all of this forecasting over time with respect to -- we talked a lot about learning curves here and I'd like to know a little -- have a little elaboration on how those learning curves were used, whether they apply to all the components in the cost buildup or not, or whether they apply to one component, like PV modules, and whether the learning curves -- you know, as the information is displayed there are abrupt changes in those learning curves so was there -- what methodology and approach was used to define those abrupt changes?

And part of this question goes to the whole concept of a learning curve, that the theory of the learning curve has to be based on some constant level of encouragement or incentive of price reduction.

And, in fact, those encouragements do change over time so at one point in time all the encouragement might be going to R&D, and then it might be going to demonstration, then it might be going to deployment. And so different types of encouragement might provide different changes in the speed of the learning curve.

So, I’d just like to hear a little bit about the methodology and approach.

MR. MC CANN: Go ahead, Miles.

MR. O'KELLY: At Itron we did not develop learning curves from a series, a time series of beta costs, and so forth. This was strictly secondary research.

So we were looking at, in most cases, where learning curves were used we were looking at work prepared by others. And while the learning curve may well apply to various components of the different types of systems, it was clear that on the PV side module-to-module costs were perhaps most appropriately demonstrated to be influenced by learning curves.

As you point out, it’s true that the different factors can influence the actual costs, without regard to strictly the aggregate accumulation of capacity.

But we did not develop learning curves for the different subcomponents. Those may have been inherent in some of the costs that we used in developing, as far as inflection points and the cost curves go.

What we also did was fundamentally extract, from the research of others, times, years, and costs that would be appropriate about that time, and then between those points interpolate using something of a gradual progression from one year to whether it's five or ten years thereafter.

Few of the studies had individual costs for individual years. And bringing all of these different studies together led us to coming up with costs that may have been from one specific study, and another cost ten years later might be from a different study. But we tried to bring, align those in terms of the commercial embodiments that we're envisioning.

MS. CORFEE: And this is Karin Corfee. I'm going to ask Graham to chime in on this question with respect to CSP.

MR. STEVENS: Am I on mute again, or no?

MS. CORFEE: Yeah, you're unmuted now.

MR. STEVENS: Can you hear me? Okay, great.

Yes, so on the CSP side what we did was we started with the kind of current costs embodied by the DOE loan guarantees and then we took a wide scan through the literature on what projected declination rates were projected for these various, you know, CSP and tower technologies. I'm sorry, trough and power tower technologies.

And so it's kind of a reflection of what's out in the literature and there are varying methods of literature, learning curves, you know, expert experience, et cetera, that are used to make these sorts of projections. So, this is sort of reflective of the current thinking in the literature from our numbers perspective.

MS. CORFEE: And then, Shalom Goffri, are you available to answer on the PV side? We're looking for which caller you are.

No, we're not seeing. Okay, I will say on the PV side we really did leverage existing literature and research and the aggressive scenario was the SunShot. And the SunShot, you know, does show a slowdown in the decline of module prices once you reach grid parity. So, once the module prices reach a dollar a watt then there's dramatic slowdown in price declines thereafter, so, embedded within that are the learning curves.

MR. MC CANN: And with that I believe I have a question from Edison.

MR. KUBASSEK: Yeah, I've got to catch a flight so I'd like to make some just general comments on the scope of the study, where we might take it next.

So, thank you, Mr. Rhyne, for providing the opportunity to comment on your effort to publish and update to the cost of generation model and report.

These resources are really valuable for industry stakeholders by providing a publicly available set of cost assumptions that we often refer back to.

I also want to commend your effort to seek feedback on the inputs and the methodology. These kind of interactions are essential to ensuring that the resulting estimates are reasonable, consistent with recent industry experience, are appropriately represented, and reflect the changing needs of its users.

Now, as you referred to in your opening comments, despite their ubiquitous nature, levelized cost numbers are often misinterpreted and used to justify arguments or claims of relative cost effectiveness.

In May 2011, I, along with my colleague, Mr. Carl Silsbee, represented SCE at an IEPR workshop on levelized cost modeling. At the workshop we provided five recommendations that were aimed at adjusting the levelized cost framework in such a way to enable the kinds of comparison that people naturally want to make when they look at these numbers.

So, I'd like to just revisit those briefly. The presentation is available on the CEC's 2011 IEPR webpage. And then I'll discuss some additional recommendations or things to think about as you're going forward with this project.

So, first, levelized costs should be calculated on a real, rather than nominal basis. A real approach holds constant the payments in real terms, rather than nominal terms, which allows resources with different economic lives to be more easily compared.

Second, resources should be compared on an equal capacity value basis. So, in other words, the estimated cost of a kilowatt from one resource should provide the same capacity benefit as a cost of a kilowatt from any other resource in the study.

This reflects a difference in qualifying capacity within the RA framework.

So, we suggested a cost adjustment to bring all resources up to basically providing the same level of capacity benefit.

Third, the levelized cost of intermittent must take generation resources, should consider the interaction between their expected generation profiles and the associated time-dependent patterns and market prices.

So, for instance, many, or most I believe, solar systems actually peak at production at noon, depending on the angle of the array, while market prices during the summer will tend to peak later in the day.

This issue has also been noted by economist Paul

Joskow in his paper at the 2010 Berkeley Energy Institute Electricity Policy Conference.

Fourth, the levelized cost of intermittent resources should consider the associated costs of integrating those incremental resources. What exactly those costs are have remained elusive. Nevertheless, we encourage staff to explore how those might be included, especially as ongoing research into that area is being conducted in the public face.

And, finally, dollar-per-megawatt hour numbers should not be compared when resources have vastly different capacity factors. This was an important issue for a number of participants at the May 2011 workshop.

And as I looked forward and reviewed these presentations that you'll give, I did notice, Mr. Rhyne, that you didn't put a CT right next to a CCDT.

But as you'll recall, our approach was slightly different. We actually came up with what we called the screening curve approach, where we plotted levelized cost and dollar-per-kilowatt year terms as a function of capacity factor, which had an added benefit of reflecting that fundamental resource decision between peaking, intermediate and baseload generation which could be useful for users who aren't familiar with what we're doing here.

So, these methodology issues aside, we have a few additional areas that we'd like to encourage the Energy Commission to explore.

First, as we move to an environment where a specific resource's flexibility attributes are increasingly important, it would be useful to look at how different gas-fired generation system designs, with different flexibility attributes, what their cost difference might be.

This would help us estimate differences in build outs that have different levels of flexible generation in them.

Second, we'd like to see the Energy Commission explore the difference in cost between constructing solar photovoltaic systems in urban rooftop settings versus ground mount rural settings.

Stakeholders have been interested, hey, where do we -- where is the best to place these resources. You know, the difference in land costs and system upgrade costs, transmission upgrade costs all kind of comingle together there and it would be useful to explore that.

And then, finally, generation costs are only one piece of the system planning puzzle. Any given set of resource build out scenarios will have an associated set of necessary transmission and distribution investments.

And we encourage staff to think about how to incorporate this into the cost of generation report as an educational resource for its many different users.

So, thank you again for the opportunity to provide input into the process. SCE looks forward to submitting further comments on the workshop and the final report. And we look forward to continued collaboration with the Energy Commission on the cost of generation model report. Thank you.

MR. RHYNE: So, this is Ivin Rhyne again. First of all, thank you, Mr. Kubassek for the really thoughtful comments and input. More specifically, just thank you for taking the time to be an active participant in the process, not just today, but as you mentioned at least two years ago, when we talked about this in May of 2011.

You've mentioned several inputs, some that you've talked about before and I think I may have mentioned during my opening that we really take those very seriously.

Our ability to address them are limited in two ways. First of all, the transition from talking about levelized cost to build a single power plant, under a set of particular assumptions is itself a difficult task. Extending that really a true apples-to-apples cost comparison in which we're not just talking about the cost of the plant but, also, the cost of any additional resources to equalize the generation profile, so to speak, is itself several orders of magnitude more complex. Not an unworthwhile task and certainly not something that we aren't interested in. We, in fact, are very interested in talking about those because we agree, to some extent, that there is sometimes confusion in how these numbers are used, what are they good for.

So, we're certainly going to take that under advisement and would like to continue to receive feedback from you and any other stakeholders who have input on that.

I would also mention that you talk about screening curves and that's actually a function that we've been very careful to make sure is there in the tool, itself. Although, you would have to download, it's a rather large file and it can be difficult to use. But in the report we'll make sure that we put some of that information in there so that it's more easily accessible to those who don't want to necessarily navigate the full model. And, certainly, that's appropriate.

And the other thing is that I really want to emphasize that we, as a staff, really agree that incorporating other elements of the investment decision is the key to keeping the levelized cost and the cost component pieces that we're studying in their proper context, because the system itself, and the decisions associated with those systems are built on more than simply brute economics. In other words, it's not just a payback to any particular investor but, in fact, it's meant to be a public good as the fact that the Public Utilities Commission, the Energy Commission, and a number of regulatory agencies are involved in making sure that it stays a public good.

So, elements like the environmental benefits, as well as other pieces, are a part of that decision and it's something that we want to make sure is properly held in its place so that the cost doesn't become the one and only thing we ever talk about.

Because, certainly, that's not the only way that these decisions are made and we certainly agree in that respect.

So, we look forward to your written comments and we certainly look forward to continuing to work with you and any other stakeholders on this issue.

MR. KUBASSEK: Thank you very much.

COMMISSIONER MC ALLISTER: I want to just chime in here, too. So, thanks very much for your comments and your participation in this.

And I think on the sort of energy versus capacity issue there’s a lot going on in that front right now. We’ve had the Resource Adequacy Summit with the three agencies and a lot of interested stakeholders, in San Francisco last week.

And I think the demand side capacity issue is coming into this mix in very interesting ways and is very topical right now, and could very well affect where that demand resource, and other demand side resources, certainly the storage discussion is key to that as well, and not just co-located with generation, but also just independently, you know, distributed storage and other types of storage at all scales.

So, I guess the point being that, you know, we -- this is a little bit broader than what Ivin is talking about, just specifically the cost of generation modeling within the IEPR forecasting discussion. But, you know, it could be that the marginal capacity costs of different generations, renewables and otherwise, may actually be impacted pretty significantly by where we can -- where we end up going with the demand side flexible capacity.

So, I think this is a really interesting discussion and I think the IEPR’s a good forum for it and, really, sort of broadly constituted, you know, not just in this forum, but in other IEPR forums, like the demand response discussion we're likely to have and we're going to have later in the year, I believe May 22nd is the workshop date, we can start -- we can dig into these issues in a number of ways, so I'm looking forward to that.

MR. MC CANN: So with that, I will take back control, I hope. Ah, there we are.

So, I'm going to talk, briefly, about how we took the information that Navigant and Itron provided to us and merged it into a dataset in which we could provide mid, high and low cases.

So, as I mentioned early in introducing this, we wanted a breadth of estimates, a little bit different than what we had done in the previous cost of generation models in which commenters had said that our estimates were too narrow and didn't capture a wider range of potential outcomes.

What we found when we did merge the data was that Itron and Navigant's mid-cost cases were relatively close to each other, confirming that, but that the bounding cases, the highs and lows in some cases were substantially different, so that we felt like we were capturing the full range of potential outcomes.

We also, in merging this information, tried to make sure that our highs and lows were consistent with each other. So, for example, we used the high assumptions for both the variable and fixed O&M or we used the highs and the lows for the storage and capital costs for the thermal, solar thermal projects.

In terms of findings, looking at both estimates it looks, it appears that tracking PV may be ready to overtake fixed PV in terms of cost on an LCOE basis, but that the fixed PV has a higher potential upside benefit. That is that the low-cost outcomes are potentially better for the fixed PV setups.

We also found, looking at the solar thermal estimates, that the projects with storage up to 10 to 11 hours could be cost effective against conventional resources by the end of this decade.

And that for 20-megawatt solar plants that the interconnection costs could soon become close to half of the cost of the projects out by 2030.

These tables summarize the various factors of the solar technologies. This is the mid-cost case and you can look across it to see the capacity, the capacity costs that we -- instant capacity costs, the O&M components, the plant-side losses, which are mostly conversion for PV from DC to AC, the various capacity factors associated with each one of these scenarios, and the degradation rate for the solar projects in terms of output from year to year.

The next table shows the high-cost cases for each one of these technologies.

And, finally, we show the low-cost case for each technology.

And those are -- you can look at each one of the handouts in order to see these numbers in detail.

And with that, I'm going to then move on to discussing our estimates that we developed for the renewables.

What we were doing in this section is updating the values and performance parameters that we have for biomass, geothermal and wind. So, we did drop, for example, ocean wave technology, from the 2009 estimate. I believe there were a couple of other technologies. The coal IGCC technology was dropped, as well.

In this particular area what we were looking at is we, essentially, were going into this project looking at doing minor updates to the 2009 COG data, but then as we got into the research it became apparent that the perspective on many of these technologies had changed since 2009 and that there was, in fact, more substantial updating than we had originally foreseen.

We also, in looking at the cost estimates we found that the cost forecasts for these technologies are generally more stable than the cost estimates for solar, mostly because these technologies are more mature.

But they are also, the cost estimates are a function of location and different expectations by the various forecasters.

Our methodology for updating this was to rely on secondary sources, largely NREL surveys and consultant studies that they had collected. But we did compare these results to less-detailed studies.

For example, one area was geothermal. There's many estimates out there for geothermal. The problem is that they don't distinguish between binary flash and dry steam in those studies, and we needed to be able to distinguish by technology source in doing these estimates.

The NREL studies, mostly, were able to give us those important distinctions.

We reconciled the sources to make them comparable with each other. We used our 2009 values if we had no new information.

And we only forecasted going forward changes in wind costs because the forecasts were largely not available for the other technology sources.

Looking at wind, the wind costs rose and then decreased in 2009 in large part because of various changes in demands for wind turbines.

The wind case, if you look at our trend for the mid case, it reflects a move toward the lower cost case estimates over time.

One of the interesting findings is that it's much more common to see 100-meter towers now, beyond the current 80-meter height standard.

The class five sites have largely been developed and there's much more development of class three standards, they've become much more dominant. And so we've dropped the class five estimates and moved to class three estimates.

Station usage was significant on wind projects in the studies, which was a bit surprising and it's something that we had not seen in previous studies.

And another one is that the European -- there's been a couple of European studies that have shown that there's degradation in a wind farm output over a period of time, about .3 percent per year.

Here are forecasts of wind class three cost forecasts. So, you can see relatively stable, the mid-cost case shows a decline and convergence towards the low-cost case over time.

And here is our forecast of the class four costs, again showing the mid-cost case moving downward over time.

I'll present the cost tables at the end, comparing the different technologies.

Moving to biomass, we focused on fluidized bed boiler systems that are the utility scale.

Biogas technologies are typically still at the DG scale. And that's an important make in all of our studies is that we're looking at utility scale, not DG scale technologies.

Our revised values reflect numbers that are consistent with what you would find for a mature coal plant boiler technology. Boiler technology's been around for more than a century and so there are small, incremental changes, but you're not going to have large changes in the technology going forward.

And biomass plants are typically less than 50 megawatts due to fuel collection and transport costs.

And this is particularly important in the west where there are areas where the amount of biomass that is available, particularly in the Rocky Mountain region, in order to collect something large enough to fuel a 50-megawatt plant or either coal-firing of coal plants would involve large transportation costs.

For geothermal we looked at binary and flash technologies. An interesting outcome is that the binary technology has no GHG emissions because it's a closed system. Whereas flash has an amount of GHG emissions, but less than what you would find with dry steam, like at the geysers' plants.

Well exploration and drilling costs are the largest cost variable in this and there is also a long development stage, up to seven years, seven to eight years for these projects.

One of the things in looking at these costs, the well exploration failure rate can have a significant effect on the cost of geothermal projects.

There's also significant well pumping loads and other O&M costs associated with geothermal. And again, the geothermal projects are typically less than 50 megawatts to match the resources that are available.

Summarizing the mid-cost cases, this table shows the biomass, geothermal and wind costs. Again, the instant cost, the various O&M costs, the losses, the capacity factors that are assumed with those cases, heat rates where applicable, the annual degradation rates in both capacity and heat rate, and the CO_2 emissions per pounds for megawatt hour for each of the technologies.

Here's our high-cost cases as you can see here, and then our low-cost cases. And all of these, again, are included in the presentation report for your review.

And with that we'll take any questions on the renewables.

MR. TUTT: Good afternoon, Tim Tutt from SMUD. And the one question that I had relates to the issue of biogas. And I agree that it's mostly, when developed and used on site, a DG kind of technology, not a central station technology.

But I would encourage the Energy Commission not to lose sight of the issue of biomethane that's able to be used in large, combined cycle power plants. It has been a growing use for renewable power in California in the past. And as we open up in-state sources of biomethane in the next couple of years it's going to continue to be there.

So, somewhere, and I mean, obviously, it doesn't affect a specific power plant cost, except for in the natural gas side, in a sense, but somewhere that cost should be captured and catalogued. Thanks.

MR. MC CANN: One of the useful things that we can do with this model, for example, is to take in a forecasted biomethane gas prices and input that into the model to run in a, for example, combined cycle plant and see what the cost difference is compared with the greenhouse gas allowance. So, the model has that flexibility to do that analysis very quickly. So, thanks.

MR. RHYNE: And, actually, Tim and any other stakeholders listening online, I would encourage if you have some source that you would like to see us use in terms of prices for biomethane going out into the future, certainly submit that into the record because we would certainly consider running some values that include biomethane and talking about that in our report, if it's something of interest to a wide variety of stakeholders. So, that's certainly something we will consider.

All right, so we've reached that point in the day when everyone is starting to look rather tired, and we have reached about the midpoint of our agenda for the day.

It's about five minutes after 12:00 and I'm going to look towards the dais over here whether or not a return at one o'clock is appropriate.

So, we'll break for lunch and we will try and start at -- yeah, we'll start back after that.

Richard, I think, has one last thing to share.

MR. MC CANN: Yes. For those of you who are interested in commenting, when you call back in please sign in so we can identify you. We often have just numbers here and we can't identify people by their number. So, thank you.

MR. RHYNE: And with that we are out for lunch. Thank you all very much. We'll see you back in an hour.

(Off the record for the lunch break at 12:07 p.m.)

(Reconvene at 1:08 p.m.)

MR. RHYNE: All right, so it's a little after 1:00 and I'll ask everyone in the room to find your seats. We're going to go ahead and get started.

So, the second half of the day is dedicated to dealing with another two major topic areas. The first is fossil fuel-fired generation and the second is the estimation of levelized costs and ranges of levelized costs estimates as developed through the Analytica Cost Tool.

So, our next set of slides is very short and that's because it's common to all fossil-fired generation -- all natural gas-fired generation, I should say, which is in order to estimate the cost of operation over the lifetime of any of these plants, it's important to also include the cost of fuel, as that's a major component of any of these plants.

So, we have to use gas price assumptions from somewhere and our best option is to use them from a source that is publicly vetted and in some ways open to the public to participate in.

And our choice in this case is to use those generated by the Energy Commission's Natural Gas team. And that is the mid case, which was presented on February 19th, at the Energy Commission, for a workshop, that those estimates are available on our website.

And then to generate high and low price values. Now, we could have used the high and low cases associated with that. However, as noted at the February 19th workshop, the band that was initially generated, and those are preliminary prices, the band that was originally generated is very narrow. In fact, more narrow than the history suggests we should be looking.

And so for the purposes of the model which is used to create the cost of generation estimates the -- we used a procedure wherein we took the EIA's forecast out over a number of years and compared it to the actual gas price trend that was recorded for Henry Hub, and then calculated the errors, both high and low, associated with that forecast.

And then adjusted those prices to a burner tip price, which is to say the price that's delivered to the gas plant is not just a Henry Hub commodity price, but it’s actually the price of the commodity, plus the price to transport and deliver.

And so just very quickly, there’s an actual wellhead price in this slide that is the red line, and then you’ll see it numbered by years, the EIA forecast values up through 2008. And this is a methodology that was used in the 2009 forecast and is being reconstructed here.

So, as you can see, the actual wellhead price includes values that are within some band of a number of these EIA forecasts. We have a number of forecasts that are higher. Some, as you can see, in the mid to late 1980’s, ’85, ’86 and ’87 we have a few that in retrospect look very accurate, for example 1990, but that themselves deviated for some period of time from the actual wellhead price.

And then we have a number of wellhead price forecasts that run well below the actual values, those from the mid ‘90s onward.

And so what this does is it creates a band and a probability band around which we can then expand from any reference case that’s taken.

And so what we did is we took the reference case, as provided at the February 19th workshop by the CEC’s Natural Gas team, and applied the high and low price bands that the -- essentially, moving that out to the 90th percentile high and the 90th percentile low, so that we could come up with a range.

And as you can see, that range actually diverges over time and that's what you would expect to see with a real world forecast in terms of the uncertainty and complexity of the system that actually compounds on itself over time.

And so, our forecast becomes less and less reliable as you go further and further out into the future.

What this does is it gives us a reasonable range of high, mid and low natural gas prices which can then be fed into the cost of generation model to help create the high, mid and low cases that are run through that model.

And then we would use those through Analytica to create the bands of uncertainty which you'll see later on in the day.

So, creating this gas price forecast is just one piece. And as you saw with the renewables, there's a wide variety of assumptions that are necessary to calculate these costs.

Now, I am going to ask you to think way back to this morning. We will pull forward a little bit, think of the financial assumptions that were shared this morning. There were financial assumptions for natural gas and there were financial assumptions for renewables. We spent the morning talking about renewables. So, we have a number of financial assumptions, a set of fuel price assumptions.

And now Richard McCann, from Aspen Environmental, is going to go ahead and share the results of our gas-powered plant survey so that you can understand that methodology and how we came up to estimate which prices we did. So, I'll turn it over to Richard.

MR. MC CANN: Thank you, Ivin. This is Richard McCann. Welcome back. Let me find my section.

So, this -- in this section we're going to talk about how we develop the natural gas plant capital and operating costs.

Will Walters of Aspen, who I hope is online somewhere, down here towards the bottom, yes, is available to answer questions, as well. He supervised the admission and collection of the survey data that is used in doing this analysis, and Will is on the phone.

So, what we have done is that we completed a survey previously, in 2006 that we used in the 2007 IEPR model. And in that survey we were focused on the new combustion turbine and combined cycle plants that had been built largely since 1997 and even more so since 2000, that were in existence.

The types of plants that were surveyed were CEC jurisdictional plants, plants that had to go through the AFC process to get a siting permit. They were both simple cycle or combustion turbines and combined cycle plants with the steam turbine configuration. And these are not cogeneration plants, so these are solely electricity generation plants.

The information that we requested was -- included capital costs. And we've updated those since the 2006 survey. We relied on the 2006, pre-2006 data for plants built earlier. And the operating costs for plants that had been operating for more than one year.

Our survey sample had about 47 plants, with roughly 17,000 megawatts of capacity. There were 29 project owners. Of those, the simple cycle projects represented -- there were 22 simple cycle projects that represented about 3,000 megawatts and there were about 25 combined cycle plants, representing about 14,000 megawatts.

The ownership breakdown was 30 projects that were merchant plants, four that were investor owned, and 13 that were municipally owned plants. And you can see in the parentheticals the breakdown of technology type.

We had various operating cost requests that we sent out for 19 simple cycle and 24 combined cycle plants, and we had additional capital cost requests beyond what we had collected previously for simple cycle and combined cycle, as well.

In our capital cost request we asked for the total installed cost of the project, the breakdown of the gas turbine type and model information.

The same sort of information for the steam turbines, where it was applicable, obviously not applicable to combustion turbine, inlet air treatment type and the costs associated with that, cooling equipment type and cost.

Water treatment cost and whether it was zero load discharge.

Site footprint and land costs and then the total construction costs with site prep, linear utilities' costs, licensing and permitting costs, and various air pollution control and offset costs were required.

Here's a sample of the survey form that we asked the operators to fill out. They could also request that their data be maintained as confidential, and I'll talk about that in a second, so they could check off various components that were to be maintained as being confidential. And you can see how we identified the information that was sent out. We did this both by e-mail and then with phone call follow up.

In our operating cost requests we looked at annual costs, again, over the time period from 2006 to 2011, operating hours, with start and stop hours, and the number of starts, duct burner fuel use where applicable, their annualized gas price, water consumptions and costs per acre foot, staffing and personnel costs, ongoing costs of various miscellaneous items, maintenance costs, and then their definition of fixed versus variable costs.

And again, you can see the operating cost survey form that we submitted, quite similar again to what we did in 2006. And, again, they could also request that their information be held confidential.

We got a really high survey response rate given that these were not -- the answers were not compelled for the owners of these projects. We got an 85 percent response rate. We got 81 percent of the project owners. So that what we had is the larger owners were more likely to respond.

We got 90 percent response rate from all merchant projects, 100 percent from investor owned, and 69 percent from muni projects.

For simple cycled combustion turbines we got a 91 percent response rate. For combined cycle projects it was 80 percent.

For capital cost estimates we got a 75 percent response rate for simple cycled and 83 percent for combined cycle.

And for operating costs we got higher response rates, 89 percent for simple cycle and 79 percent for combined cycle.

And this compares to the 2007 response rate where we got 100 percent, but that was basically in 2007 there was a mechanism for us to be able to compel a response from these individual projects.

So then we brought in the data, collected it, and compiled it. We wanted to make sure that the data that we developed was adequate for cost of generation purposes. We didn't find any major flaws in the data that we collected.

Even though there were some minor data problems, we found -- we didn't find that there were significant issues. There appeared to be some anomalies in the duct firing fuel use reporting, but overall we found that the data was adequate for our model use.

So, to develop estimates for heat rates and capacity factors we were able to rely on publicly available data in the QFER, which is the Quarterly Fuel and Energy Report data that the Energy Commission maintains on individual power plants.

And so, we derived weighted averages for the heat rates and capacity factors based on 2002 to 2011 data.

Some of this data, if you see the thermal efficiency of gas-fired generation reports that the staff issues, there's some minor differences between what we have estimated in the model and what they have. The two major reasons for those differences are that we dropped partial first-year operation in our analysis because we were looking for full year estimates. And we also used planned capacities for the projects, rather than the actual capacities reported by the projects in large part because we are doing a planning exercise so, if anything, we would be using estimates that correlated with the planned capacity amounts that are being reported by developers.

From the QFER data you can see the heat rates that we derived by different technologies for the low, mid and high cost cases.

For the combustion turbines the heat rates ranged from 9,980 BTUs per kilowatt hours to 11,890. The rationale behind the bounding cases of low and high is that we picked the 10th and 90th percentile points in the distribution from the QFER data.

You can see the ranges for the combined cycle plants as well, ranging from 7,030 to 7,480 BTUs per kilowatt hour. Slightly lower heat rates for the H Frame efficient, highly efficient combined cycle plants.

And you can see, similarly, for the advanced technology combustion turbines that we had a drop in the comparable heat rate.

For the capacity factors we showed a range from 3 to 7 percent for the older technology, LM-6000 CTs and a range of 4 to 11 percent for the advanced CT technology.

For the combined cycle plants we saw, actually, a much bigger range than we had seen previously in the 2009 data, when we were looking at it. It was ranging from 40 to 71 percent for the typical Frame F combined cycle plant. A bit higher for the H Frame technologies, ranging from 55 to 90 percent and this reflects a wider range of operating environments that these power plants are running in these days.

One notable thing, also, the model has different capacity factors for the combustion turbines, depending on ownership.

An interesting finding is that for the investor-owned utilities they're combustion turbines are actually running around one percent on the capacity factor, whereas the publicly-owned combustion turbines are actually running at about seven and a half percent capacity factor. So, there's an operating -- that's an example about how the operating environment apparently changes the operational profile of a combustion turbine quite a bit.

We have a summary of our survey. These are averages that we derived from the power plant survey. The instant cost numbers include some permitting costs that we calculated externally, so that they don't come directly from the survey.

You can see the ranges of these costs. The combustion turbine costs are higher than they are for the combined cycle plants because what we found in California is that aero-derivative combustion turbines are the dominant type of technology and that these are more expensive than the cost-per-kilowatt for combined cycle plants.

This is different than, perhaps, other places in the country where they have Frame F CTs, instead.

We also derived fixed costs and variable costs for these power plants based on the data that we collected.

And this particular table shows the capacity factor for the combustion turbine for the publicly-owned utility scenario.

There’s the heat rate estimates that we derived. We also had degradation rates for the capacity and heat rate that, actually, we derived from 2009 and used those values again. And the CO2 emission factors per megawatt hour are shown on the far right.

These are the high-cost cases, the high cost in these cases for operating parameters were either chosen as the 10th and 90th percentile or the maximum/minimum if the percentiles were outside the bounds of the surveys that we saw. So, we were bounding, basically, within what we got from the survey.

And then you can see the low-cost cases, as well, for these various technologies as compared to the individual technologies.

You can see that there’s a larger range around the combustion turbines than there is around the combined cycle plants on this.

And with that we conclude.

The online question was?

MR. RHYNE: Repeat when the survey was conducted.

MR. MC CANN: The survey was conducted last fall, so we began this survey in about September -- or August or September and then collected the data over the fall, compiled it in January.

MR. RHYNE: So, are there any questions or comments for myself or Dr. McCann regarding fossil fuel generation? Yes?

MR. PIETRUSZKIEWICZ: This is Jon Pietruszkiewicz of Black and Veatch, again.

The question I'd like to ask is about the gas turbines versus the combined cycles. I think it's clear that the aircraft derivatives are more expensive than the industrial frames, but the idea that they're more expensive than the combined cycles is new to me and the fact that they've doubled -- the average gas turbine price has essentially doubled in the last couple of years, according to this data.

So, I'd just like to have a little more elaboration on that.

MR. MC CANN: When we first did this study in 2006 we were somewhat surprised by those results. And then they've continued to show up in our survey. When we look at the survey responses the numbers haven't really moved much in those relative ratios between those projects, they've remained the same in California.

Maybe it's different than the rest of the country, but in California the combustion turbines are costing more per kilowatt than the combined cycle plants. It's a surprising result. I mean, people have taken issue with that. But as the best we can tell, it's because of the dominance of the aero-derivatives in this State.

MR. MARCUS: Hi, I'm Bill Marcus. I'm with JBS Energy, representing TURN this afternoon.

And I want to point out that the numbers that you are putting together here are -- end up being used in unexpected places and, therefore, need considerable documentation and vetting. In particular, the PUC has been using them for some of the utilities for marginal cost, and revenue allocation, for the calculation of the cost effectiveness of demand response, and those types of things.

So, when I'm sitting here looking at combustion turbines are more expensive than combined cycles, I have to ask the question what is the real cost of capacity, being the least cost of reliability in the State of California.

And mechanically plugging some numbers in at the PUC may well get you the wrong answer.

The other things that I think need to be documented more clearly, you know, in terms of use by the PUC and in other venues, are some of the costs related to operations and maintenance, insurance. Like, I've got to say, the insurance numbers people have used for generation have been extremely high by comparison to the utilities and in the past.

So, I would just encourage everybody to, you know, sharpen their pencils, get some documentation together, be very careful because, you know, maybe some other people are putting more weight on these numbers than perhaps the Energy Commission, itself, is.

And with that I'll -- I'll probably make a few more written comments on the 21st. Thank you.

MR. RHYNE: Just to that point, we had some choices to make with regard to how we gathered the data. But we certainly are well aware of the fact that these numbers are used and in sometimes unexpected ways. So, we'll certainly take to heart the admonition to keep the pencil sharp and make sure that this is well documented, as well documented as some of the confidentiality requests would allow us to do so.

MR. HATTON: Hello, Curt Hatton, PG&E. I had a couple of questions, the first one being on interpretation.

So, when I see the category labeled "generation turbine 49.9 megawatts" in your discussion you talked about that a lot of that may have been driven -- the cost have been driven by the fact that a lot of them were aero-derivatives.

Was the actual cost, though, based upon a combination of some were aero-derivatives and some were not, or is this meant to be just indicative of the cost of an aero-derivative?

MR. MC CANN: Virtually, every CT that's been built in California is aero-derivative. So, the survey -- I'm not actually even sure there is a non-aero-derivative CT that has been built in California, because we never found a frame out, so that's really the basis for these cost estimates.

And then what we have is actually a scale economy. We calculated the scale economy moving from 49 to 100 megawatts in that analysis.

MR. HATTON: My other question was, as far as the survey it's my understanding that they were -- a lot of the plants were built in different years. What methodology did you use to move the cost from one year to another? For example, you know, how much inflation there was, or if it was in a time when perhaps turbines were very expensive, or very inexpensive. Did you take into account those variables?

MR. MC CANN: We didn't adjust for the different turbine cost estimates. We did use the GDP deflator to bring the costs to a common level, the construction cost numbers.

We don't have a good cost index for the -- for example, the individual components of the various power plants.

So, I believe, I have to look at which GDP deflator we used for that.

MR. HATTON: The other question I had, for example on combined cycle, they can be dry cooled or wet cooled. Did you modify or how would interpret, when I see combined cycle 2CTs, is that a dry-cooled facility or is it a wet-cooled facility? And when you came up with your average cost did you modify anything for that?

MR. MC CANN: We looked at the cost differences for the cooling technologies and we found that there really wasn't a statistical difference between the cost of the plants based on the cooling technology that was used. It was -- in part, that's why we have the high and low bounds.

But the fact is that there wasn't really any one factor driving the plants towards the high or low bounds that we could find in the data that we had.

MR. HATTON: So then, I guess from your answer there, you did not make a specific -- any changes based upon whether a plant was or was without dry cooled --

MR. MC CANN: Right.

MR. HATTON: -- but you looked at the ranges and you thought that the high and low ranges that you came up with captured those differences?

MR. MC CANN: Yes, it did. And as I said, we couldn't put our thumb down on what that cost difference was in the data that we had. When we dug, we could not find a statistical validity for their difference.

MR. HATTON: The other question I had was on the new frame, the H combined cycle you had a large range of capacity factors and I was wondering what sort of drove those because it's my understanding there's not a lot of those actually in operation so --

MR. MC CANN: No, and that's actually the range that came from the operations of that plant over the time that it's been operating, it's had that kind of range from year to year.

MR. HATTON: Okay, thank you.

MR. RHYNE: We had an online question about which of these plants in the survey fall under baseload generation versus peaking generation?

And to the extent that those labels are valid anymore, we could say broadly that most of the combined cycles operated largely as closer to baseload, although many of them are beginning to slip down into something like load tracking rather than pure baseload or pure peaking. And then most of the simple cycles, the combustion turbines operating in peaking type roles although, again, it’s not entirely valid to lump them into a single category in that regard simply because the choices for operation, as Richard mentioned, do vary by ownership type.

And so, for example, we see that the publicly-owned utilities seem to be operating their combustion turbines for a larger percentage of the time than the investor-owned utilities. And that’s one of the factors involved.

So, hopefully, that addresses the question.

So, we have another online question about how certain elements of the survey can be found?

The surveys that are not labeled as confidential are available under the docket as IEPR -- I believe it’s 1C that the docket number that these -- so, it’s the 2012 IEPR update docket, 12-IEP-1C. You can visit our website and the surveys that were collected, that are publicly available are collected there.

So, if you’re interested in taking a look at that source data, it is available.

Those that requested confidentiality and were granted are not available there and will remain confidential.

Are there any other questions or comments here in the room?

MR. MARCUS: Very quickly on the combined cycle issues. One of the major concerns of the Energy Commission is clearly what is it going to cost to get flexibility for renewable integration, meeting RAMP, all of these types of things.

And I'm wondering whether this project has investigated that cost both for newly constructed combined cycles and for items that could be retrofit onto existing combined cycles to improve their flexibility, such as auxiliary boilers, changes to reduce minimum capacity, those types of things.

MR. RHYNE: That's an excellent question. It is, unfortunately, a bit outside of the scope of this particular project to attempt to do that particular investigation.

One of the things that we have seen that is indicative of, I think, the need perhaps for more analysis along those lines is along the lines of what Dr. McCann was saying in terms of we see a larger operating, a wider operating range in terms of capacity factors for these combined cycles than we have previously.

And we're also seeing, I think, a higher number of start and stops, if I recall correctly from the data. I would have to go back and look at that again.

But both of those seem to indicate that flexibility is becoming more highly valued. It's showing up in the operational profile. And whether or not there are cost-effective options for kind of doing better at getting that built into the generation infrastructure is, as I said, a little bit outside the bounds of this particular project.

Okay, any more questions in the room or online?

No. And then with that, I will shift from talking about all of these component costs and I'll emphasize, again, that these component costs are available as a handout here. I believe we might have used up the last ones here in the room, but they're also available online.

So, most of these tables and many, many more tables, along with many more graphs being explicit about the values that go into this are available as part of the documentation for this workshop.

But we're going to shift, now, to talking about levelized cost, how that was calculated, and one of the tools that was used to do so in conjunction with the actual levelized cost model.

We have Dr. Max Henrion with us today, who under contracted helped put together a tool using the Analytica software package, that allows us to look at the results from a levelized cost model in a more probabilistic and, we think, more defensible and robust way.

So, I'll ask Dr. Henrion to join me here at the podium and we can turn the microphone over to him.

MR. HENRION: Thanks so much, Ivin. I appreciate the chance to present this today.

This is more in the nature of describing the tool and then Ivin will be showing some of the results using that, after this.

So, do I click this to make it go forward?

Okay, so ACAT, which is kind of a hyper acronym, Analytica COG Analysis Tool, is essentially a way to take this cost of generation spreadsheet and do a wide arrange of sensitivity analysis and also uncertainty analysis on Monte Carlo that is easy to do within Excel by itself.

And some of you may be very familiar with range sensitivity analysis and Monte Carlo, others not so much, so I'll kind of give you a brief introduction to what it's up to, first, the range sensitivity and then the Monte Carlo.

So, as we've seen, there's been a huge amount of effort to estimate low, mid and high values for each of the parameters, both financial parameters, and technical parameters, cost parameters for each of the technologies.

And so one of the questions is, you know, how much do each of these parameters, how much difference do they make to the results?

You know, which is the source of uncertainty that we should be worrying about the most?

And so we do a range sensitivity analysis to explore that.

There's, of course, as we've also seen, uncertainty in the natural gas prices. Here are the low, mid and high values that Mr. Rhyne already presented, I think.

And so, range sensitivity produces this graph, sometimes called a tornado graph for reasons that might be obvious. So, down the left of the graph we list the various variables that affect the -- where we're looking at their effect on the levelized cost of energy.

And in this case, this example is a 100-megawatt, single access PV plant. And, actually, we're looking at what the predicted costs are for 2020.

And we're saying what if we take the overnight capital cost as the one at the top, and vary it from its low value to its high value, keeping all of the other parameters at mid value, so that's what range sensitivity is doing.

And then we're saying as we do that variation we get a bar. You know, red going down to the low value, blue going up to the high value, and then we vary the variables by the width of that bar, the width of that sensitivity. And that's what makes it look like a tornado somewhat.

And we can see right away, probably not a big surprise, that the overnight capital cost is by far the largest contributor of uncertainty for a PV plant, followed by capacity factor, fixed plant losses.

And at the very bottom, no big surprise, fuel price. Well, there isn't any fuel price.

Here's a similar slide, a range sensitivity plot, or tornado chart for a 200-megawatt natural gas turbine, again in 2020.

Here we can see, reflecting what Dr. McCann was just mentioning, the uncertainty about the capacity factor. It turns out that this the largest contributor to uncertainty about the levelized cost of electricity for the gas turbine, followed by the capital cost.

So, these kinds of charts are just a way to get insight into which of these uncertainties really matter and how much relative to the other ones.

So, this is one way to think about the uncertainty and this is just a user interface of this ACAT tool. I'm not going to say too much about it, just to say that it works with a spreadsheet.

The Analytica software that implements this is sometimes tagged beyond the spreadsheet, but this is just to show that it can play nicely with Excel if it needs to. And in this case the Analytica tool is essentially running the spreadsheet, loading in numbers for some of the key uncertain parameters, you know, low, high or random, as we all see, generating the results. And then it can also put the results back into a spreadsheet.

So, Monte Carlo simulation is a way to represent the uncertainty probabilistically in each of these parameters. And in this version there's a couple of simple options.

So, for each, low, medium and high value, the yellow, blue and red on these charts, we can fit either a uniform distribution or a triangular distribution.

The uniform is set -- both of them are set so that they treat the low and high as a 10 percentile and a 90 percentile. So, there's a 10 percent chance that the actual value will be less than the low value and a 10 percent that it will be larger than the high value, which is why I was very happy that the -- when I asked the question earlier on about what the low and high for the PV and the CSP were interpreted and he suggested that 10 and 90 is about right.

Now, we hadn't rehearsed that, by the way.

(Laughter)

MR. HENRION: So, or we can fit a triangular distribution, in which case we're taking the mid value to be the mode or the peak of that triangle. And just to make an important point here, the mode is not necessarily equal to the median and you'll see later why that might be significant.

And so we sample randomly from each of these distributions for each of the uncertainty quantities, use COG -- for each of these samples, load these sample values into COG and get the corresponding LCOE, and repeat that, in this case I think 1,000 times, to build up a probability distribution over the LCOE.

And just to say, you know, there's different ways to visualize the uncertainty. The probability density functions are perhaps most familiar.

And underlying that, as I explained, the Monte

Carlo is generating a thousand sample values and we're just showing a hundred here. And we're estimating the probability density function from those thousand samples.

Or we can look at a cumulative probability distribution curve, saying what's the probability that the real value is less than X.

Or we can use these probability bands, sometimes called two key box plots, or college scarves, because of the light and dark blue.

I got into an argument with a friend of mine who went to Oxford, and I went to Cambridge. Oxford and Cambridge have light and dark blue, so that's the origin of that name.

Anyway, so the point is that actually, I think, although that's perhaps not such a familiar view, in many ways that's, perhaps, an easier one to understanding when you're combining -- when you're comparing multiple distributions.

So, here's an example of changes in levelized costs looking at the density function. The red is a combined cycle, 800-megawatt, and the blue is solar PV.

And here's looking at those same distributions as box plots or scarf plots.

And the full range goes from 1 to 99 percent.

The kind of light blue goes from 10 to 90, and the dark blue is 25 to 75 percent.

So, this is apparently telling us something a bit interesting, which is that it looks like the costs might increase between 2012 and 2020 for the gas, because of high gas prices, and this is actually including the RTC, so the expiring RTC explains the PV change.

But again, we aren't certain about that. If you look at the ranges of the distributions, it's also possible it could be a reduction.

So, I will now hand over to Mr. Rhyne to actually show some more of the results from this.

MR. RHYNE: Thank you, Dr. Henrion.

Our next piece here is to talk about the actual levelized cost estimates and ranges as they were generated through a combination of the cost of generation model, which uses the component cost inputs as we've talked through most of the morning and part of this afternoon on, and the probabilistic approach as described by Dr. Henrion.

And I think it's -- before I show these, it's good once again to emphasize that these numbers should be used with great care. First of all, because they are to be taken as draft and preliminary in the sense that they will be revised based on input from this workshop and other stakeholders, but also because it can be very tricky to estimate the correct value of cost appropriate to the use you are seeking.

And I would encourage anyone, who wants to use a component of this, or the levelized cost values, themselves, to either contact someone who understands these values or to reach out to someone, either here at the Energy Commission or the PUC, someone who really understands levelized costs and how they are used.

So, the idea that there is no one cost associated with any of these technologies or any of these projects leads us naturally to understand what is the reasonable range of cost.

I can build two identical gas plants in different parts of the State, under different ownership criteria, perhaps even at just different times of the year and they will cost something very different, and it’s important to understand what is that reasonable range.

And so our previous model, the one that was released in 2009, introduced high and low values, but they applied them all simultaneously, such that we ended up with a very wide range of values but we had no way of determining which -- how broad that range was actually plausible.

We ended up looking at subsequent efforts where we took only one, perhaps the most important value, meaning the one that was the largest driver of levelized cost, and varying only that one to create a more narrow band.

And this present effort, obviously, uses the probabilistic approach as described in Analytica.

So, this table, and I apologize, we're not going to spend a whole lot of time on it, we're going to show you what these are side by side.

So, we calculated highs and lows for the simultaneous, everything to the high and everything to the low, and then only varying the most important.

And what we came out with was a range, and I'm not sure if you can see this, but the mid cost value was represented here in red, and that range is represented in the light blue.

And so what we end up with is, as you can see on the left-hand graph, the range, if everything is pushed to its highest high and its lowest low, is quite broad for all of these technologies as they're laid out here.

But if we vary only the one that is assumed to be the largest driver of levelized cost, it narrows the band significantly.

Now, that is something of an arbitrary choice, however. If we vary only one, is it also possible that -- are there interactions with other cost variables? How do we know that that's, in fact, the right approach?

Well, the short answer is that we don't and which is why we reached out for expert help in this regard.

And so we did this again, and this time we ran that analysis using Analytica. And this is a comparison of our single value high and low versus the probabilistic range of values. And I'll show you what those -- and, actually, Max showed some of them in terms of the box plot there. You can see them all here and it was very similar.

And this is important to understand because with regard to costs it is often only one or two factors that swamp everything else.

And so as we run through and use the mode and the triangular distribution for most of the factors that we showed you, we end up with a range of values that are the 10th and 90th percentile.

Now, I apologize, this is a little bit difficult to read. They are presented online and you can look a little more closely at this.

But, really, it helps us understand why, or I should say how big a band are we really looking at here?

And so in using that we're able to have some degree of confidence. It's roughly 90 percent certain that a combined cycle, or a CT, or utility-scale solar PV project is going to fall somewhere in that band given -- given that you accept that our initial cost input values are, themselves, accurate and that our process for developing probabilistic approach is also the correct approach. Both of which, by the way, we are wide open to stakeholder feedback if you believe we've got those values or this approach incorrect.

It's important, we've done -- I believe our team has done a great deal of good work in terms of coming up with that, but we are a limited number of minds chiseling away at a rather complex problem.

And so we believe that the results end up looking better and more realistic when all of those of you who are participating today, both in person and online, participate as well.

And so this table takes a look at how the Analytica tool varies the -- when we run this, we come up with a value that is not necessarily identical. The mid value, if we take --

I'm sorry, let me back up a little bit. Our traditional approach is to take all of the values that we have come up with, set them all at the mid case and call that the reference, that's the middle.

Analytica, by using the probability distribution approach, allows us to begin to see whether or not that was in fact the correct way. And in some cases we end up with some numbers that are very close to what we would have come up with in the mid, but in other cases we get some divergences.

And this is -- this table we're going to show you in this format here.

So, what we did is we took and ran the cost of generation model at the mid case, and then we took the median value, derived from the Analytica took, and compared the tool to see just how large the levelized cost difference is.

And in some cases you can see that the COG value was higher and in some cases the Analytica tool showed a higher median value. That has to do with the fact that the mode of a distribution, meaning the most frequent value, is not necessarily the same as what we would think of as the median for any one of those cost factors.

So, once we run those altogether and we run them upwards of 2,000 times, and we allow all of those different factors to vary along the probability distributions that we showed you, we end up with median values out of Analytic that vary, to some extent, from the middle case values of the cost of generation model.

And what we end up with here is a set of levelized costs and the actual -- the full table of levelized costs for mid case, and this is for 2013, is again on this slide here and we would ask everyone to take a look at it.

But, really, it's important to say focusing on levelized cost is beginning to look at the horse in the wrong direction. We would ask you to look more closely at the cost components, the inputs associated with each of these individual technologies where your specialty, where your expertise, where your particular interest lies and help us get that right.

If you have an understanding of probabilistic approaches, take a look at how we did that, as well.

I think somebody earlier talked about documentation. We absolutely believe in documentation. We also believe in feedback. Those things will help us get this better.

And once we get those corrected, the levelized cost will be whatever the levelized cost is because that calculation is standard. It's not a difficult calculation to make once you have all of the pieces in place. It's about getting those pieces right.

And so at the end of the day if the values of the cost of generation mid cases vary greatly from the Analytica case that's fine, we think that's an appropriate value once we get all of the input pieces correct.

So with that, we come to the close of the section focused on levelized cost and the Analytica tool.

Before we move on to closing this out and opening it up to broader comment, I'm going to ask if there are any questions for myself, for Dr. McCann, or for Max Henrion about the levelized cost estimates or the probabilistic approach.

MR. MARCUS: Can you just briefly describe how you set the discount rate for purposes of calculating the levelized cost of energy?

MR. MC CANN: So, the discount rate that's in there from the developer or owner's perspective, so we used the weighted cost of capital based on the after-tax rate for the combination of equity and debt in the model.

MR. RHYNE: Okay, any other questions here in the room, or comments?

MR. TAYLOR: This is a question about the LCOE.

MR. RHYNE: I'm sorry, could you state your name just quickly for the record?

MR. TAYLOR: I am George Taylor.

This is a question about the LCOE calculation. When you're doing that for a source, such as wind, that requires another primary source to be available to balance it, do you take into account that by introducing that variable source you have reduced the total average output per year of the primary sources and, therefore, you have reduced their ability to recover capital?

Because what one could argue is that if you wanted to be able to take a weighted average of the costs on your last slide, when you put up those LCOEs, if you were to take those columns and attempt to do a weighted average of what it would cost to construct a system with a certain generation mix, according to the calculations I've done, if you don't take into account the fact that the variable sources take away operating -- not operating hours, but the average level of output for the dispatchable sources, then when you add those up you're not able to recover all the capital and so, therefore, you underestimate the weighted average cost of all the sources when they're mixed together.

Does the question make sense?

MR. RHYNE: It does make sense. The short answer is each of these are calculated as though they are the only project, rather than a full mix.

We don’t attempt to do that and that actually gets, to some extent, to the system question raised -- the system cost, sorry, question raised by Mr. Kubassek from SCE, which is to say that there are other intricacies involved when you attempt to mix these together into a larger picture.

MR. TAYLOR: Right.

MR. RHYNE: And I don’t necessarily disagree at all with what you’re saying with regard to having to be very careful about adjusting for the changes in capital recovery based on the lower capacity factors.

It’s difficult, however, at this point to ascribe a change in capacity factor to any one solar or other renewable project, simply because it’s a drop in the larger California-wide bucket, if you understand what I’m saying.

So, this project, I think as we go forward, in the next iteration, would be very interested in hearing more from stakeholders, like you, on how we might appropriately capture more of those broader system effects and the costs associated with them.

MR. TAYLOR: Okay, let me follow up with you afterwards. That would be fine.

MR. RHYNE: Good.

MR. TAYLOR: But just to say one comment about that, I don't think the mathematical case that I'm pointing to here actually depends on the capacity factor of any of the variable technologies. It actually just depends on how many megawatt hours of generation have been replaced from the primary sources.

Because for each one of those that's replaced that is a capital recovery, you know, megawatt hour that cannot be actualized by the original source. So, I think it's independent of the capacity factor.

I think it occurs any time there's a variable source which must be paired with a primary dispatchable source but, yet, it takes away the operating, the average operating output of that source, so that was the question.

MR. RHYNE: I would hesitate to jump wholeheartedly into that only because it's also dependent to some degree on the change in demand over time.

And so as demand grows there is a need to meet that new demand, so it's not a full-fledged replacement if demand is also growing.

So, it's the rate at which renewables come online and you have to net out the amount that would have been necessary to meet new demand.

And so there is -- it actually does become a matter of capacity factor once you account for that, as well.

And we can certainly have more of this conversation at another time. And this is actually exactly the kind of technical conversation that we absolutely want to encourage more of.

MR. TAYLOR: Okay, thank you.

MR. RHYNE: We have an online question. Apparently, I wasn't very clear in that the use of distributions in the Analytica COG Analysis Tool we use the triangular distributions, rather than the uniform distributions for the variables.

And I don't recall, I don't think we used the uniform distribution for anything in particular. Although, it looks like Dr. Henrion's nodding his head in approval, so I didn't get that one wrong.

So, yes, so that's what we did.

Are there any other questions with regard to the levelized cost here in the room, or online?

All right, so seeing none of those, we'll move on to closing.

Our next steps here -- actually, I'm sorry, I'm going to pause there before we go into this.

So, we have built into the schedule, now, kind of an open period. We've asked along the way for questions and comments. I know that we have at least one person who has some broad comments to share, so I'm going to invite Ms. Chase Kappel to come to the podium, please, and share her comments.

MS. KAPPEL: Hi, my name is Chase Kappel. I'm here today on behalf of Pathfinder Renewable Wind Energy and Zephyr Power Transmission.

Pathfinder is developing 3,000 megawatts of wind generation and associated mitigation land in Wyoming. and Zephyr is developing a transmission project that will enable the high-value, Wyoming wind generation to be delivered to California.

I realize today is very focused on in-state sources, and the cost components, and cost estimates for those sources.

But in general we want to make the comment now, kind of early in this IEPR process, that we would like to see this -- we'd like to see IEPR also expand its consideration to projects that deliver to California and are not simply in California because there are renewable projects outside of California that are capable of providing needed diversity among the renewable projects at competitive prices.

In particular, wind generation from Wyoming is a cost-effective option for California, even when taking into account the costs of long-distance transmission.

Wyoming wind generation, in particular, has a comparatively high capacity factor for wind of 49 percent, which looking at some of the in-state capacity factors is very high.

And integration of Wyoming wind generation provides geographic diversity to the intermittent renewable resources in-state. And by that we mean that the Wyoming wind substantially increases the reliability of California's wind portfolio.

In other words, on high heat days California may have lower in-state wind generation, but Wyoming would not.

And also, we would like to introduce into this docket a couple studies that further discuss the contributions of the out-of-state wind -- of the out-of-state wind resources.

The first of these is "Wind Diversity Enhancement of Wyoming and California Wind Energy Projects."

This is a University of Wyoming study that was done by their Wind Energy Research Center. And this report focuses on the importance of diversity in wind resources and specifically considers the benefits of combining Wyoming and California wind resources.

And then the other report is a WECC report, it's the 10-year Regional Transmission Plan. This report is specifically intended to assist decision makers in considering the costs of out-of-state resources, and considering where to build new transmission.

And among other conclusions, this plan concludes that there is a total cost saving in using long-distance transmission to access remote renewable resources in comparison to just a local renewable generation portfolio.

So, those are my brief comments. And I'm not sure how I could introduce these into the docket. If you would like simply paper copies, or if I could e-mail you, or if someone on the staff links our electronic versions of these reports.

MR. RHYNE: So, any docket -- anything you'd like to go to the docket, there's an e-mail address here at the end of my presentation. Actually, I'll just go to that.

So, there's an e-mail address for the docket at energy.ca.gov. You'll just note the docket number, 13-

IEP-1B -- 1 bravo.

And just if you'll cc myself, as well, it has my e-mail address on there and we'll make sure that that gets into the docket.

MS. CHASE: Great. Thank you.

MR. RHYNE: Thank you.

Are there any other public comments here in the room?

MR. TAYLOR: So, once again, I'm George Taylor and I'm a PG&E customer in the Bay Area.

The other question I'd ask you, when you're calculating the LCOE for a variable source do you take into account whether that source saves 100 percent of the fossil fuel that would have been consumed by some primary dispatchable source to produce the same number of megawatt hours, or do you assume that it saves 100 percent of the fuel that would otherwise have been consumed?

MR. RHYNE: That's actually a very good question. We calculate the cost to the generation developer. And what that means is that we're not attempting to calculate the avoided costs associated with unburned fuel that would have been necessary from other sources.

If we were calculating for the utility, that might be more appropriate, but in this case that's not what we're attempting to capture here.

MR. TAYLOR: So, if I were looking at this from the point of view of a customer, and I was trying to use your numbers to go back and estimate what the wholesale price of electricity should be in my market, or that my provider would face, I can't use your numbers to do that because you're not taking into account the full system costs. You're only taking into account a subset of those costs; is that right?

MR. RHYNE: Well, it would -- in order to calculate a wholesale cost, and I'm going to be very careful here because I don't want to go too far afield, calculating a wholesale cost on any given day is about understanding what is available on the system, what it costs to pay for that existing, and then what additional pieces must have been added.

This work is about capturing the cost of those net additions to the system. It is not an attempt to go backward and capture how much did it cost to build a plant say five years ago, that is currently operating and providing the system.

So, it would be necessary to estimate the cost of continuing to pay down that investment, plus any new investment, plus the operational cost, plus anything else that might be appropriate in that particular calculation.

So, using this would only be one small piece of that larger calculation.

MR. TAYLOR: So, I understand your answer there is related to capital costs, but I was actually asking about fuel consumption, which is not related to past history, that's a current question.

So, what you're saying is that your report, if it were being viewed by a policymaker, a policymaker would have to understand that you are not presenting the full cost of each of the technologies that society has to bear, or the customers have to bear, you're only presenting a portion of that cost and you're leaving some of the rest of it out. And that cost would be borne by me, as a customer, but that's not being addressed by your report. The fuel issue is what I'm addressing.

MR. RHYNE: I'll say that's a qualified yes.

MR. TAYLOR: Okay.

MR. RHYNE: In the sense that to capture the full social cost, borne by everyone, is much more than just the cost of any individual project.

MR. TAYLOR: Right. Do you have the information or do you think there is information available here, in

California, that would tell us what the fuel savings are of the various intermittent technologies that were listed?

MR. RHYNE: There are a number of places where that specific topic is discussed, and that really becomes a question of avoided cost. That is often discussed at the California Public Utilities Commission.

And there are, I'm almost certain, studies that would touch on that topic, although I can't recall any of them just off the top of my head.

MR. TAYLOR: Okay, thank you.

MR. RHYNE: All right, any more questions or comments here in the room?

Seeing none, any more questions or comments online?

COMMISSIONER MC ALLISTER: Actually, can I -- I wanted to actually address that question because I feel like it's -- certainly, the implication is that is not a very relevant and vital question. I'm thinking of this in terms of, say, the Renewable Portfolio Standard where, you know, there are very clear compliance mechanisms in which -- you know, that every year, every compliance period the Public Utilities Commission will look at the investor-owned utilities, the Energy Commission will look at the publicly-owned utilities and gather data about the overall -- you know, the source of all their -- you know, every kilowatt hour that they sell, essentially, to determine the percentage that comes from renewables.

And so, the projections in the studies going forward, and a lot of the interaction between the utilities and the regulators and, you know, all the stakeholders involved certainly do those calculations to figure out what the overall resource mix is.

But that's a -- so understanding what the situation is and where we're going I think is happening in a number of different forums and is very much built into the system at this point.

Asking the question of does an individual project offset, you know, sort of how many kilowatt hours of different types of generation is offset by a particular project is actually, I think, probably a more difficult thing to determine and does really depend on the dispatch.

And maybe I'm mischaracterizing your question.

So, I think that there's sort of the macro view in where we're going, and I'm pretty comfortable with where we're going there. The tracking individual kilowatt hours for different projects is a little bit more -- in a market-based system is a little difficult.

MR. TAYLOR: Could I just clarify? I didn't want to suggest that it was important to look at individual projects. I was actually asking about information that would address the entire generation mix, the big picture.

So when you aggregate everything, which I think is partly what LCOE reports typically do, when you try to aggregate everything I think it's important to ask yourself what is the big system effect? When you're finally done what have you paid for in terms of facilities and how much have you changed the fossil fuel consumption picture by investing in another kind of facility.

And so, to clarify, I wanted to ask it at the high level.

COMMISSIONER MC ALLISTER: Yeah. And that's right I think that's happening in the various planning exercises.

You know, on the other side you know the fossil fuel guys are out there -- you know, with all this new procurement of renewables, the fossil fuel guys that are out there with their traditional plants, the plants that used to operate, you know, at a certain capacity factor and now are actually less demanded, you know, that squeezes their margins in a different direction.

So, it’s a fairly complex sort of question when you talk about specific plants.

MR. MARCUS: Hi, I’m Bill Marcus, again. If I can just amplify on this, I think we’ve got two different sets of tools here.

And the Energy Commission, in this particular study, is using the levelized cost of energy, which is a screening and planning tool.

And there are production simulation models that simulate the system, which are the dispatch tools which would answer the questions we were just having in incredible granularity and also incredible confidentiality.

Because these models are now expensive and the utilities, they’re commercially sensitive, utilities won’t run them. Other people, market participants will run them, and nobody wants anybody to see anything that could possibly affect the near-term price.

And it’s a little frustrating for me, as an intervener, not to be able to see some of this stuff.

But I think we’ve got two different tools here and I understand the concern of the PUC and the Energy Commission for both of them. And I think that’s some of the policy on renewable integration is can we do this better?

And that's not a discussion for this workshop, but can we do this without building large numbers of new gas plants? And I think that's going to be probably one of your most critical policy efforts in this IEPR. Thank you.

MR. RHYNE: So, we've reached the point where I think we're about ready to close.

Before we do, however, I want to acknowledge someone who's been silent through this particular workshop, but whose work actually has been speaking volumes, whether anyone realizes it or not. Joel Klein, my associate and co-worker here, at the Energy Commission, actually has really done the lion's share of the work with regard to keeping this particular project on track.

He has been more than just helpful, he's been really the person pushing the ball forward and I want to thank him, personally, for his hard work on this particular project.

As well as the rest of the project team, Aspen Environmental, Dr. Max Henrion from Analytica, Itron, Navigant. There were a number of people from a wide variety, both inside and outside the Commission.

And I want to thank the Commissioner, as well, for supporting this work as we've gone forward.

As you can see on the screen, the moment of release is at hand. However, I will ask that you provide comments. If you have comments, if you've thought about things that you didn't share, if you shared something that you think really just needs to be captured in words, please submit that by March 21st.

And you can mark that just with a docket number. An e-mail, if it's just that simple, will suffice. If you'll just send it to the docket at energy.ca.gov, with a carbon copy to myself, the e-mail is there.

If you have some other piece, perhaps a study that you'd like to enter into the docket, that is hardcopy, you can mail that the old-fashioned way, again marking it with the docket. And the physical address is located there at the bottom of the screen.

I want to thank everyone, both online and in the room for participating.

And before we go, I'll ask the Commissioner if he has any last-moment comments before we do?

COMMISSIONER MC ALLISTER: Yeah, I leave it to Ivin, you should be -- you're the fearless leader of this activity and I'm really just the fly on the wall today. So, I really appreciate all the interaction and look forward to having your written comments on the record. And thanks for those of you in the room for coming today. I know it's not easy to get here and participate in an all-day workshop.

And folks out there in the World Wide Web thank you as well for participating.

So, thanks again, Ivin and staff, and congratulations on a good event.

MR. RHYNE: Thank you very much. And with that we close out our workshop. Have a wonderful day. Drive safely.

(Thereupon, the Workshop was adjourned at 2:25 p.m.)

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