BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of	) Docket No.: 12-IEP-1D
	)
Preparation of the	)
2012 Integrated Energy	)
Policy Report	)
Update (2012 IEPR Update)	) Public Workshop

LEAD COMMISSIONER WORKSHOP
ON
RETAIL RATE AND COST ISSUES WITH RENEWABLE DEVELOPMENT

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

TUESDAY, MAY 22, 2012
10:00 A.M.

Reported by:
Peter Petty

APPEARANCES

Commissioners Present:

Carla Peterman, Lead Commissioner, 2012 IEPR
Andrew McAllister, Commissioner

Staff Present:

Suzanne Korosec
Al Alvarado
David Vidaver
Karen Griffin
Lynette Green

Also Present (* Via WebEx)

Panelists

Richard McCann, Aspen Environmental Group
Jon Pietruszkiewicz, Black & Veatch
David Lewis, Pacific Gas & Electric (PG&E)
William Walsh, Southern California Edison (SCE)
Jim Tracy, Sacramento Municipal Utility District (SMUD)
*Randy Howard, Los Angeles Department of Water & Power (LADWP)
Jason Simon, California Public Utilities Commission (CPUC)
Brendan Pierpont, Climate Policy Initiative
Chloe Lukins, DRA
*Stephanie Chen, Greenlining
Tom Brill, San Diego Gas & Electric (SDG&E)
Amrit Singh, PG&E
*Russell Garwacki, SCE

Presenters

Severin Borenstein, UC Energy Institute

Public Comment

Steven Kelly, Independent Energy Producers Association (IEP)
Rusty Klassen, Tensleep Advisory
Valerie Winn, PG&E
Daniel Kim, Westlands Solar Park
Ray Pingle, Sierra Club
Carl Silsbee, SCE
Elise Brown, UC Davis Energy Institute CGE Collaborative

INDEX

INDEX

P R O C E E D I N G S

MAY 22, 2012 10:04 A.M.

MS. KOROSEC: Good morning everyone. I'm --

COMMISSIONER PETERMAN: Good morning, everyone. We're going to get started, so everyone please find their seats and we'll begin so we can get everyone out on time and give attention to all our panelists. Thanks.

MS. KOROSEC: Thank you, Commissioner Peterman. Good morning. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit, and welcome to today's workshop on Retail Rate and Cost Issues with Renewable Development.

Just a few housekeeping items. For those of you who may not have been here before, restrooms are in the atrium, out the double doors and to your left. We have a snack room on the second floor at the top of the atrium stairs, under the white awning. And if there's an emergency and we need to evacuate the building, please follow the staff to Roosevelt Park which is kitty corner from the building and which also has a lovely Farmer's Market there today if you want to try to hit that today at lunch.

Today's workshop is being broadcast through our WebEx Conferencing System and parties do need to be aware that you are being recorded. We'll make an audio recording available on our website a couple of days after the workshop, and we'll make a written transcript available in about two weeks.

In addition to our panel discussions today, we've set aside two opportunities for public comment, one before lunch for those of you that may have to leave before the end of the day, and one at the end of the day after all our panel discussions.

During the public comment periods, please come up to the podium at the center of the room and use the microphone there so we make sure that the WebEx folks can hear you, and so that we make sure that your comments are captured in the transcript. We will take comments first from those of you here in the room, and then from WebEx participants and those participating by phone only. When you do come up to speak, it's helpful if you can give our Court Reporter a business card so that we can make sure that your name and affiliation are reflected correctly in the transcript.

For WebEx participants, you can use either the raised hand or chat function to let our Coordinator know that you would like to make a comment or ask a question, and we'll either relay your question or we'll open your line at the appropriate time. For phone only participants, we'll open your line at the end of each of the public comment periods.

We're also accepting written comments on today's topics until close of business May 29th, and the notice for today's workshop, which is available on the table in the foyer, and also on our website, explains the process for submitting comments to the IEPR docket. And now I'll turn it over to Commissioner Peterman for opening remarks.

COMMISSIONER PETERMAN: Good morning, everyone. Hello to everyone here in the room, as well as on WebEx. Welcome to today's workshop. I'm Carla Peterman, Lead Commissioner for the 2012 IEPR, as well as Lead Commissioner for Renewables. Today's workshop on Cost and Retail Rate Impacts of Renewables is the fourth of seven workshops that the Commission is doing as a part of the IEPR 2012, to develop a Renewable Strategic Plan.

The outcome of this workshop will be a list of recommendations that will assist the State in meeting its near-term and medium-term goals for renewables, in particular the 33 percent RPS, in the most efficient and best way possible.

This workshop is a complement to what I believe was our first workshop on Net Benefits for Renewables. It is important as we work towards reaching these goals that we identify the ways possible to lower the cost of renewables, as well as increase their adoption amongst and by various parties in the State. We're also cognizant that rate impacts are real and we want to talk about these and, in particular, look for some solutions about how do we mitigate some of the rate impacts and transition some of these rate increases over the long term so that they're acceptable and that energy still remains affordable.

This is an incredibly important topic to the Commission and to my fellow Commissioners. Chair Weisenmiller wanted to be here today, but he is traveling, but sends his regrets. I'll be joined on the dais at different points by some of my fellow Commissioners. I also had the opportunity to discuss this topic with some of my colleagues at the Public Utilities Commission and their staffs are monitoring this process, as well.

Costs and rates? That's a large topic and we're not going to cover everything today, so I encourage you and welcome you to submit more extensive written comments. We may not touch on all the technologies today, but all of them are important to us. I will be reviewing all your comments personally and look forward to your recommendations and suggestions, so I ask that we move forward and look forward to hearing from our panelists. I ask that you keep your comments within the time periods so that we can continue to move forward and hear from everyone. So with that, let me turn things back over to Ms. Korosec and thank you to all the staff now, and I'll say it again later, for your involvement, as well as the panelists for taking the time today. Thank you.

COMMISSIONER KOROSEC: Thank you, Commissioner Peterman.

Every two years, the Energy Commission prepares an Integrated Energy Policy Report that covers a variety of energy topics and provides policy recommendations to the Governor.

In 2010, Governor Brown directed the Energy Commission to prepare a plan to expedite permitting of the highest priority renewable generation and transmission projects. To provide the foundation for that plan, the Energy Commission developed the *Renewable Power in California: Status and Issues Report* as part of the 2011 IEPR, which described the status of renewable development in California and challenges to future renewable development. It also described activities already completed or underway to address those challenges. The report also established five high level strategies as the basis for a more comprehensive

Renewable Strategic Plan that's being developed under the 2012 IEPR Update Proceeding.

As Commissioner Peterman mentioned, today is the fourth of seven workshops that we're holding as part of the 2012 IEPR update on topics related to those five strategies, dates of which are shown here, and the discussions and input from the workshops will be used to identify specific near term actions that the State needs to take to begin addressing the challenges that were identified in the Renewable Report.

The second strategy that was identified in the report relates to evaluating costs and benefits of renewable energy projects. Again, as Commissioner Peterman mentioned, our first workshop on April 12th covered the benefit side of that equation, and today we're focusing on the costs, including renewable cost estimates and drivers, as well as how costs are considered in utility procurement and in rate design.

Our agenda for today begins with a panel discussion of total cost estimates, projections, and drivers, which includes presentations by Energy Commission staff, Aspen Environmental Group, and Black and Veatch; that will be followed by an opportunity for public comment for participants unable to stay until the end of the day; and then we'll break for a one-hour lunch. We'll reconvene after lunch with a panel on cost considerations in utility procurement and policies to reduce costs, and then to a presentation by Severin Borenstein, and a panel on rate design; we'll have another opportunity for public comment at the end of the day and hope to adjourn by 5:00.

So I'll provide a very brief overview of information related to today's topics that was presented in the Renewable Report, which discussed costs mainly in the context of cost challenges to developers of renewable projects, but also touched on cost trends and renewable energy subsidies over time, as well as some R&D efforts to reduce renewable costs.

The Renewable Report included a discussion of levelized cost studies for renewable and conventional generation, including some of the limitations of those studies, levelized cost as the present value of the total cost for financing, building, and operating a generating plant over its economic life, converted to equal payments per megawatt hour. Cost components are grouped into fixed and variable costs, with variable costs representing from 50 to 80 percent of the cost for a combined cycle natural gas plant, while fixed costs represent the bulk of costs for most renewable technologies.

The Renewable Report compared three sets of levelized cost estimates for renewable generation technologies, one prepared by Black and Veatch for the Renewable Energy Transmission Initiative, which is shown in green; one developed by E3 for the PUC's Long Term Procurement Proceeding, shown in blue; and finally, one developed by the Energy Commission in the 2009 IEPR Cost of Generation Project.

The Renewable Report pointed out that the range of costs for a technology can be more significant than the differences in average cost between technologies. And the levelized costs are not necessarily representative of average costs because specific project costs depend on cost components that can vary, for example, transmission interconnection costs are different, depending on location, or wind turbine costs may depend on manufacturer inventory levels.

The Renewable Report also acknowledged some of the limitations of these levelized cost estimates. They don't reflect cost reductions that we've seen in the past few years, particularly for solar PV technologies, nor do they consider time of delivery payments, transmission and integration costs, for example, although some renewable technologies like Solar PV and Solar Thermal may have higher levelized costs than conventional generation, they do produce generation when it's most valuable and can actually be competitive with conventional generation on a time of delivery basis.

The estimates also don't include DG technologies, which is something that the Energy Commission intends to evaluate as part of the 2013 IEPR, along with making updates to cost driver information, and reflecting advances in renewable technologies, and I believe Mr. Alvarado will touch on that at the beginning of the first panel.

Although comparing leveled cost estimates can be useful in understanding the challenges faced by renewable developers, it's only part of the story. Other cost factors like environmental review and permitting, transmission and distribution interconnection, integration and financing also affect project viability.

The Renewable Report discussed how environmental and permitting challenges can delay or jeopardize project development and increase development costs; environmental concerns can also lead to legal challenges, causing delays and higher project costs.

Compliance with environmental mitigation requirements can also pose significant costs, for example, estimated mitigation costs for the 370 megawatt Ivanpah Solar Tower Project in San Bernardino County were

$34 million. There can also be costs associated with emission offsets for renewable technologies that have air quality impacts.

DG developers also face permitting challenges, including complex and sometimes overlapping permitting requirements. In the Renewable Report, a solar panel installer in Southern California was quoted as saying there were 50 different permitting authorities within 50 miles of his office.

Varying Codes, Standards, and fees are also a challenge, with a Sierra Club survey showing that fees varied widely among municipalities, and even within municipalities, for projects of the same size; for example, in Los Angeles, permit fees for 131 kilowatt commercial solar PV projects varied from zero dollars to $46,000.

Interconnection at both the transmission and distribution levels is also a challenge and can be lengthy and expensive. And there are also costs associated with integrating variable and intermittent renewables into the grid, while maintaining system reliability.

And with the economic downturn, it's more of a challenge for companies to get affordable financing and we're also continuing to see under-investment in the renewable energy sector, which will affect the development of next generation lower cost technologies.

One effort to reduce the time and cost associated with environmental review and permitting, both for transmission and generation, was the Renewable Energy Transmission Initiative, which identified 30 competitive renewable energy zones and their corresponding transmission interconnections and lines, for the most cost effective renewable generation development with the least environmental impact. Findings from the RETI process are being incorporated into the Desert Renewable Energy Conservation Plan which, by helping developers choose sites with minimal environmental impact, will reduce delays and mitigation costs.

Many local governments are also helping to reduce permitting costs by pre-designating areas and defining renewable development standards in their counties to reduce permitting roadblocks and, therefore, delays in project development.

The Renewable Report also discussed efforts to reduce interconnection costs, including the RETI and DRECP processes which, in addition to addressing environmental issues, are helping to reduce interconnection costs by identifying priority areas for renewable generation and transmission development.

The Report also identified the possibility of allowing upsizing of transmission projects to provide capacity beyond what is currently needed, which can reduce the need for costlier upgrades in the future to accommodate renewable development in those areas.

Another suggestion was for local governments to work closely with utilities to identify project sites near transmission and distribution infrastructure, to help reduce interconnection costs to developers.

For projects connected at the distribution level, the Renewable Report discussed fast tracked elements that are available within each of the State's interconnection processes, which will help streamline interconnection of smaller projects and reduce delays that can add to costs.

Also, the Report talked about a KEMA study of DG interconnection in Europe that provided some insight into lessons learned there and indicated that, if Inverters in the U.S. were required to include equipment that allows utilities to actively manage the Inverter, interconnection studies could be completed quickly and at lower cost.

Another suggestion from the KEMA Study was to restrict the amount of DG that could be interconnected to certain parts of the system, which lowers the risk of backflow and other impacts, and could help interconnect large amounts of DG at relatively low cost.

Other efforts that will help reduce interconnection study times and costs are the new Combined Generator Interconnection Process that uses a cluster approach for studying interconnection requests, and the new cluster study approach for distribution connection generators that allocates cost of an upgrade among all generating facilities in the cluster who request interconnection.

For integration, the Energy Commission, PUC, and CAISO are continuing to work together to determine the cost of renewable integration. The Renewable Report looked at three types of infrastructure that is being studied to support high levels of integration, energy storage, demand response, and gas-fired units, and we'll be talking more about these in our June 11 workshop, but relative to today's workshop, the Renewable Report points out that each of these integration options has its own cost challenges, for example, how to develop cost-effective energy storage options that can deliver the necessary services in the timeframes needed, or how to modify revenue streams for natural gas units that will need to be appropriately compensated for operating differently in order to provide integration services.

To help address investment financing challenges, there are federal tax credits and accelerated depreciation and property tax exemptions that can help reduce the cost of renewables. As you can see from this slide, tax benefits can have a significant effect on levelized cost calculations for various renewable technologies.

Tax Benefits discussed in the report include the Federal Business Energy Investment Tax Credit, the Renewable Electricity Production Tax Credit, and Accelerated Depreciation. Several renewable projects have benefitted from the allowance under the American Recovery and Reinvestment Act to convert the Investment Tax Credit to a cash grant that can offset as much as 30 percent of project costs, and the production tax credit, which provides incentives for renewable generation is also helping renewables.

In 2005, the U.S. Energy Information Administration analyzed the effects of the PTC and suggested that it could increase U.S. installed wind capacity by more than 500 percent if it continues through 2015. However, the PTC for wind expires at the end of this year and for solar in 2016, which may affect the ability of new wind and solar projects to get financing.

The Federal Government also offers Accelerated

Depreciation to help provide project capital at the front end of a project, with most renewable energy assets allowed to be depreciated over a five-year period. A 2009 Lawrence Berkeley National Lab study found that Accelerated Depreciation can reduce total PV system cost by 26 percent.

To help address shortfalls in R&D investments, the Energy Commission's Public Interest Energy Research Program provides funding for projects that reduce renewable costs by improving technology efficiency and performance, reducing environmental impacts, and developing Smart Grid and energy storage options. Some of the examples shown here include demonstration projects for new PV, biomass, and wind technologies, as well as a technology to create additional revenue streams for geothermal facilities by extracting silica from geothermal waters for sale to industrial users.

In addition to the discussions of levelized cost and the different cost drivers for renewables, the Renewable Report talked about cost trends for solar technologies. As I mentioned, we've seen significant cost reductions in the past years for solar technologies and, as global production capacity of PV panels increases, we're likely to see even greater declines in cost. The Renewable Report includes this figure, which shows how worldwide panel production has doubled every two years since 2002, and notes that, each time production capacity doubles, PV costs decline by roughly 20 percent.

Although solar thermal electric and solar PV were historically thought to have higher levelized costs than conventional generation, the Renewable Report noted that, based on recent contract bids, this seems to be changing. The Energy Commission's Investor-Owned Utility Contract Database indicates that the majority of solar thermal power tower technology contracts signed and pending are below the 2009 market price referent. Also, while in the past DG projects were considered more costly due to higher transaction costs and lack of economies of scale that, too, appears to be changing. At the time the Renewable Report was published, PG&E and SCE had filed advice letters with the PUC stating that all contracts signed under their Solar PV programs were also below the market price referent.

The Renewable Report also noted that future trends could include additional cost savings that may occur as a result of cap-and-trade, which are not reflected in levelized cost estimates.

And, to take advantage of these declining PV cost trends, the Renewable Report suggested focusing on developing the low hanging fruit in the early years while we're continuing to reform permitting and interconnection processes, and then take advantage of those cost reductions and improved regulatory structures in later years.

Finally, the Renewable Report discussed the perception that renewables are more highly subsidized than other forms of energy, and noted that a study by DBL Investors showed that renewable energy has actually been under-funded relative to other energy sources; this figure from the DBL study shows the historical average of annual energy subsidies for oil and gas, nuclear, biofuels, and renewables. The study also compared subsidies provided in the first 15 years of each technology and concluded that renewables have received less than 10 percent of the funding received by the oil and gas industries, and noted that the Federal Government continued to underwrite those industries long after they had matured.

One more thing, although this wasn't included in the Renewable Report, I wanted to provide some cost information from the PUC's most recent quarterly RPS report to the Legislature. The PUC report says that, from 2003 to 2011, contract costs increased from $0.054 per kilowatt hour to $0.133 per kilowatt hour, for several reasons. The IOUs contracted with existing renewable facilities at the beginning of the RPS program and, in later years, with mostly new facilities which require higher contract prices to recover capital costs needed to develop a new facility. And other reasons included changes in the mix of technologies, increased commodity costs and, in some cases, demand exceeding supply.

The PUC Report also noted that bids from the 2011 RPS solicitation which weren't yet available for inclusion in their report, show lower costs than bids in previous years and pointed out that contracts approved in 2011 represent contracts that probably began negotiations in 2009, and since renewables have matured significantly since then, in future years contract prices could be lower, still.

So that's a very quick summary of the discussion of cost issues that are in the Renewable Status and Issues Report. I encourage parties to look at the full report for additional details. And at this point, we will move to our panel discussion and I'll introduce Al Alvarado from the Energy Commission staff as our Moderator.

MR. ALVARADO: Good morning. I'm Al Alvarado. I'm with the Electricity Analysis Office here at the

Energy Commission. I am the Moderator for the first panel and the focus of today's panel discussion in on the Cost for Developing and Operating Renewable Generation Technologies, a discussion about the key drivers for these costs, and the cost trends, what we may expect as we move into the future.

The Energy Commission has engaged in calculating the levelized costs for different generation technologies for a number of years, the last effort to identify the levelized costs for different generation technologies occurred in the 2009 IEPR, so our cost estimates at this point are quite dated and I think Suzanne might have identified some of those concerns.

In developing this range of costs, we had to consider many variables that go into the calculation of levelized costs, this involves either the operating characteristics of the power plant, the financing elements, even the tax incentives, and each of these variables of themselves provide a range of uncertainties that need to be considered to develop the cost estimates, therefore, as we moved into developing the cost estimates, there's no single point calculation for the levelized costs, but rather a range of levelized cost estimates that was reflected in Suzanne's chart where she compared our cost estimates to E3, and I believe it was

Black & Veatch for RETI.

Staff and with the assistance of Aspen Consultants have developed these costs in the past, and we've also developed a model that is intended to be transparent and easy to use for any party that cares to take the tool and consider different scenarios for their own calculations, but it also has a lot of our cost driver information that might be valuable to other parties.

The Energy Commission staff will be updating the cost drivers for the key generation technologies for this next IEPR, this effort will be running through the year. This slide, I know it's very difficult to read, but this does reflect a lot of the key inputs that we will be evaluating for each of the generation technologies, like plant characteristics. We need to have a good understanding of plant-side losses, transformer losses, transmission losses, the heat rates, degradation.

Regarding plant costs, we would like to identify the instant costs, the installed costs, and the construction period. When we get into variable costs, you know, that gets into some variables like how many operators are needed for each plant, and salaries, and so it really -- we do drill down to a fine level of information based on whatever is available. And the outputs will provide the levelized fixed cost, the variable costs, and we also can develop screening curves to determine how some of these levelized costs may vary, depending on the capacity factor of some plants, that could be very significant for some of the technologies, especially like wind, that is becoming much more efficient and can operate at higher capacity factors.

This is just a snapshot of the range of levelized costs we calculated back in 2009. As you can see, the red line is the average cost, but the blue bars represent really the range of the levelized cost estimates. And for some of the technologies, these ranges can be quite wide. The bar is really bound by, I would say almost a book-end set of variables, you know, for example, some of the renewable technologies, the upper bound might be the difference between with and without tax incentives, or as, say, the capacity factor I think for this next effort, we would like to focus on the probabilities of how these range of the cost variables may actually fall, so we're expecting that our next round of localized cost should have a much more narrow band of cost values.

This chart is generally our work plan for this intended goal of having something completed for the early part of the 2013 IEPR that can serve as an input for further electricity system studies. Where we are right now is basically the yellow box. We're developing data requests on the cost drivers, which we're expecting to receive information from each generation technology, surveying developers as we've done in the past, which has been actually quite interesting, we found where some generation technologies with the very same configuration can have very very different costs for so many variety of reasons, many times geographically driven.

We do expect to have a preliminary draft of the cost results for a public workshop sometime this winter, so this is going to be a major undertaking on the staff side, and with the assistance of Dr. McCann, who is to my right. And maybe with this, maybe I can shift to the panel discussions. We're going to have Dr. McCann presenting an overview of their prospectus on cost, and then Mr. -- I'm sorry, John -- Pietruszkiewicz, thank you, with Black & Veatch will also cover some of the information that they have based on their own activities. With that…. Unless, Commissioner, do you have any questions?

COMMISSIONER PETERMAN: No questions, I'll just make an observation that the last time we collected this data was 2009 and, so, I'll be interested in hearing from the panelists which cost input, which inputs to the model, the cost generation model, you think might have changed the most since that period. And, in particular, where we're focused on the 2013 IEPR, is thinking about renewables since this has been quite a fast changing space since 2009. Thanks, Al.

DR. MCCANN: And thank you. I'm Richard McCann with Aspen Environmental Group. We're the lead contractor on the planning contract which supports the Energy Commission staff. And, as Al mentioned, we've been working on the Cost of Generation Model since about 2003 or 2001. And I'm just going to walk through our overview of how to approach this. Next slide, please.

What we have is -- I wanted to go through and address the three questions that were posed for this workshop, and just summarizing it, I'm going to discuss a little bit about what are the effects of the range of costs in renewables in California, what have been some of the recent trends, and what are the important regional differences. And then the second question, what are the important non-technological factors to consider? And that may actually be the most important aspect of looking at this issue. And then, finally, what are the other important events and trends to consider? And really, I'm going to focus more on how to frame looking at these issues, rather than the actual values behind that, because we're going to develop those more as we develop the cost of generation model, which we should have the model all put together by this fall.

And I think that, to start off, I want to talk about how we want to develop these assessments for policymaking consumers, that is, you sitting at the panel, you're a consumer of what we produce for you.

And I think one of the important things is the importance of perspective, looking at it as a planning agency rather than as an investor, or looking at it in some other way, that it's important to keep in mind that particular perspective.

And then, considering the multitude of factors that affect cost and value; relying on an average or an expected outcome can obscure the real policy choices or constraints that you see. So, for example, one of the things that comes up is the solar tax credit is one of the salient issues, well, if you take an average of that, what does that mean? That you have half a tax credit? You actually have to face -- you're facing a dichotomous choice in that sort of situation and you need to understand that range; an expected number is not going to give you an informative answer.

And the second part is, second thing is to have cost presentations that are transparent about the assumptions so that you can discern what issued you need to focus on; for example, the expiration of federal tax credits or other important planning considerations -- locale, regional considerations, financial issues that need to come up. And those sorts of things need -- you need to be able to pull those out of the presentations that are made. Just being told that $100 a MWH, and then somebody walking away, doesn't help you at all.

And then, finally, understanding the reasons for why these ranges exist and what you can do about affecting those ranges, having that kind of information is very important, so you have to have those ranges described in digestible pieces with clear delineation. So, for example, the combinations of factors together that cause a particular range to occur is an important piece of information in terms of following the presentations that are given to you.

So there are some principles for comparing costs that are presented here and often they're jumping around between different numbers that are presented in these various workshops, and trying to be clear about what you're looking at is important for understanding those cost presentations. There's a difference between value and cost, and there's also a difference between market price and cost. The value and the cost for renewables is not necessarily the same. So, for example, if you have a technology that can load follow, so, for example, the Geysers Geothermal Plants can often load follow vs. a technology that is relatively intermittent like Solar PV, there's a certain value, a difference between those two, so you can't directly compare the two costs of those technologies, you have to understand what the underlying bundle of attributes that you're getting is from those two different technologies. So, for example, geothermal has CO_2 emissions associated with it, whereas Solar PV does not, so each of them presents tradeoffs in what you're getting.

Market prices that you see in the PPAs can diverge from the costs, the underlying costs -- for a variety of reasons. It can have to do with the fact that the term of the contract is different than the expected life of the facility. It can have to do with trying to forward price into an industry in order to gain a foothold. So the market prices are not always indicative of the costs, unless you're in a very stable market, and we're certainly not in that situation right now.

And then you have to be careful about moving from project specific terms that really are designed for investment purposes to broad planning assumptions, so that what somebody may describe as the terms and conditions for a particular project may not fit for a broad set of projects that you're looking across. And that also gets back to the question about ranges, but you'll hear people saying, "Oh, no, it doesn't cost that much because that Project X costs something different," well, that may not be true for the general situation.

And so it's just getting back to distinguishing value, cost and market price and looking at the presentations that are getting to you. Value really depends on what are the needs of the system, which is not only just the utility system, but the environment or other particular things that you're looking for, economic benefits, affordability, costs can be expressed in different dimensions and is really only part of that value equation. And market prices and contract prices are set by the market and by regulatory conditions of the moment so that things can change within a few years if the underlying conditions have changed.

In terms of Valuation and Multiple Attributes, it used to be pretty simple to look at capacity and energy, well, things have changed quite a bit. So, for example, in Los Angeles, they have a problem with inertia, that they have to be able to keep enough power going in order to maintain the frequency level in the region. Well, it takes a heavy turbine to do that. It used to be that all power plants had heavy turbines in them, now many of the new technologies don't, so that you've got a problem that you now have another dimension that you have to consider in your planning process. And there's additional dimensions that you have to consider among those attributes. So a megawatt may no longer equal a megawatt, and that's an important consideration in looking at these. You've got to really think about what it is, what are the bundled attributes that you're trying to compare. And it really comes down to having a full understanding of the question that you're asking in terms of how you're trying to move forward. Next slide, please.

Moving on to market prices, as I mentioned before, the contract and market prices are set basically by the negotiations between the developers and the buying entities, the LSEs or utilities. And those can reflect a whole lot of different pricing strategies that are going on in the market, both by product suppliers, by the developers, and then the utilities have their own responses to various pricing strategies as to how they're trying to move the market.

And then you have different market segments, you have a long-term market, you have a real-time market, one of the things that is always interesting is the CAISO puts out a report that says every year that combined cycle plants can't make it financially because they can't make enough in the real-time market. Well the real-time market isn't where those plants are trying to make their money, it's a residual market, so they're just trying to make some extra money in the real-time market. They make it in the long-term market and we don't always see the prices in the long-term market. We do expect market prices to converge with costs over time, but the system valuation can really affect that trend of how the market prices move towards cost.

And so the bottom line is that cost measure is affected by many factors, that technology costs can be a bundle of individual components, so, for example, Solar PV is really -- it's made of a panel, which everybody has heard about how panel costs are falling substantially, but the balance of system is another large component, it's probably more than half the cost now -- that cost has been relatively stable. Wind is affected a lot by local conditions, by siting and various things, and it's turned out that in some cases the capacity factor estimates have been rather optimistic. There are differences in capacity factor, peak megawatt output, your intermittency assumptions, and what are the emission rates from different technologies?

Another one that really has a lot of effect is the financing terms. We see that, for example, differences in debt, assumptions about debt terms, can have very large effects on the final costs that we see for these projects; and trying to get that kind of information in a general way and describing it is something that is going to be very important for us.

And then, it's already been alluded to quite a bit about the tax issues so far, a continuation of the State Property tax is, in fact, one of the issues that probably is before the Commission, in terms of recommendations to the Legislature.

And then there are other issues like the effects of sales tax, which local counties are -- that is a very large benefit to local counties is the sales tax from solar projects, how are those costs determined and taxed? And then how are they shared among the various public entities is an important question.

So there are a number of policy factors that are likely to drive costs for different technologies. This is just talking at the utility scale, is a whole other set again for DG. There's a question about eligibility for the RPS, is it in-state or out-of-state? And that really affects local conditions vs.

interconnection costs, that's really the bottom line on that issue.

How are the GHG reduction credits calculated? How are the allowances disbursed? And how are they going to roll through to the ratepayers is, again, another important question. The DRECP is looking at local planning issues and, again, that really is going to affect the cost substantially, whether we have solar or wind dominating our RPS is going to be affected by that.

And then, finally, a real important question on the solar side is the sustainability of the Chinese solar industry, and then the recent trade sanctions that have been imposed by the U.S. of adding about 30 percent to the tariff cost on imports, and then they're also considering import tariffs on wind turbines, as well, from several countries.

So with that, I will conclude and if you have any questions or comments, I can answer them for you.

COMMISSIONER PETERMAN: Thank you. With regards to the Cost of Generation Model, you've noted that there are obviously a range of factors that can drive different technology costs, so where is the data coming from, then, to populate that model? Is it survey of existing projects? Expectations about future ones?

DR. MCCANN: It would be mostly surveys of existing projects, to begin with. It would be -- we're using people who have knowledge of existing contract terms and financing terms in order to help develop those cost estimates. As it was noted on solar costs, the cost trend has really been following the 80 percent learning curve trend, that is, is the costs fall 20 percent for every doubling; well, it gets harder and harder to double production as production gets very large. So we're going to see a leveling out of panel costs. The issue there will be what happens with the Chinese industry with the changes that are going on in that market. But we're basically looking around at different sources from people that we have -- we're going to try to make our information as transparent as possible so that it's really apparent where we got our information from.

COMMISSIONER PETERMAN: Thank you. And I would appreciate hearing from you in your comments, or from other panelists, or audience members, at some point about which of these factors you see as most significant, as well as the range most uncertain, or wide, if you will. And particularly by each technology class.

DR. MCCANN: Right. And I think that it's really -- the largest uncertainties that we're seeing are really in the non-technology area, some of it coming from policy choices that will be made by the State.

MR. ALVARADO: Jon, how about if you touch on your presentation and then maybe we can have some broade3r questions for both of you?

MR. PIETRUSZKIEWICZ: Sure. Good morning. My name is Jon Pietruszkiewicz. I'm from Black & Veatch, Project Manager within their Energy Division. I thought it would be useful to introduce the subject by talking a little bit about where the data comes from for costs that we project.

So, basically, we are an engineering procurement instruction contractor. We design and build facilities for others and so we sell our services and we sell complete projects, so we are a primary source of data. We don't go around and collect data from others, but we bid into the marketplace with actual costs of projects.

We also have another business, which is a consulting business, which we do independent engineering for banks and other institutions that are involved in the development or the financing of a project, and so we see the end costs, the real end costs of projects, and we factor that into our knowledge base. And then, of course, we use all of that data, along with other data, to perform studies and do things to make models and assessments for industry and for government organizations, and so during that we do additional literature search and things to compare our cost data to actual price and value data, and so we have a really good understanding of what some of the drivers are, and so I'll talk a little bit to that.

Before I talk to those, though, I just wanted to highlight the kinds of ranges that we were seeing in the costs. And as I pointed out, these are primarily data that are coming from projects that we're involved with designing and building, and so they do represent the costs of projects, as opposed to the prices or values of projects. There's also a range of capacity factors I've shown here, just to demonstrate that different technologies perform differently on the grid and in the marketplace, and you'll notice, one of the changes we made since we presented this data previously, is we've bumped up the capacity factor that gas turbines are operating at. They used to be, well, back when I started my career, gas turbines were five to 15 percent capacity factor, then they moved up and maybe they were 20-25 capacity factors, but now we're seeing the need to try to operate with low price gas and a low capital cost gas turbine at maybe up to 50 percent.

Similarly, with combined cycles, I can remember back in the early part of my career, natural gas combined cycles were all intermediate duty, they were all in the 30 percent range capacity factor, now they're in the 70's or 90 percent range.

So when you apply those capacity factors to the capital cost ranges, you can see some interesting things happen with the overall cost of electricity. And so we have to recognize that operational characteristics change with time and that changes the ultimate value and price.

The other point I want to make with this is that all these costs are basically for projects that -- this first chart, 2010-2011 costs, this is a range of costs that we saw over that timeframe. When we go to the next slide, we'll seen an additional bumping of the range just ever so slightly up and down on a few technologies, that represents what's happened in moving one or two years out to basically the now, the 2012 timeframe. And these are for projects that basically are being initiated in 2012, and might be built in 2013 or beyond. A solar plant might be built six months from now, but a biomass plant might be built two years from now. So there's a little bit of difference in how you look at the costs.

I've also added a column here to show the range of levelized cost, and when we start showing the levelized costs, then we have to factor in some of these things we've already been talking about. Somebody had to make some financial assumptions that go in here, and I can tell you that these levelized cost ranges are just ever so slightly different from previous ones we put out there, and probably because primarily the financial assumptions in the calculation of change to reflect the current development marketplace. People aren't borrowing money for the same rates they were borrowing at in 2008.

Basically, another factor I'll get to in a second, but when you look at costs and the steep change in costs, everything peaked in 2008, and everything peaked just before the financial crisis. I mean, interest rates peaked, real estate peaked, commodities peaked, you name it, it peaked. And so then things, when they recover, they recover at different rates and they recover depending on the build-up. You take copper as a commodity, and you turn copper into wire, and then you turn wire into a motor, that's a time curve that gets reflected in costs and how they recovery. So we've seen basically a flattening of the costs since 2008, and little deviations due to other things like the technological change; in wind, we've seen a little bit of technology change that allows operation at higher capacity factors and the same wind speeds as previously. In PV, we've seen bigger, more dramatic changes due to technology, and so I'll get to that in just a second.

This next slide is the overall ranges that were reflected by these financial assumptions that we're making, and the midpoints of those capital cost ranges. So I haven't even gone to the extremes with the capital costs in calculating these LCOE ranges and you can see there's quite a bit of overlap between technologies. And I will talk about things that drive those basic capital costs which expand those ranges and turn them more into prices or values.

The next slide is just a curve, just to demonstrate the -- go ahead and click through this -- we show wind first, and then solar, and then natural gas. We show natural gas at two different fuel prices here. And the purpose of this slide is just to demonstrate that these technologies do operate at different capacity factor ranges, and they do have curves that deviate due to that capacity factor, alone, but we have not included the wide bands that would be there if you put the total LCOE band for the previous slide, including all the financial assumptions and things, so you get a lot more overlapping if you did that.

So the next slide, basically I wanted to answer your question, how costs changed over the last five years. I talked about the fact that everything peaked in 2008; I also want to mention that competition has a large impact and the energy marketplace right now is dominated by the fact that lower and lower priced natural gas is becoming available on the marketplace and fairly cheap technologies are available to burn that natural gas, so that creates a little price comparison point that the marketplace is bidding against, and since all the technologies are competing, that has affected the price to some extent, to the extent that margins can change.

Also, there's a second factor that's very important over the last five years, which is the technological improvement. I just mentioned that PV is at a very steep decline dominated both by the technological improvement and by the fact that the demand for PV has changed based on the European demand and the change in policy in Europe. And so it's interesting that a change in policy in Europe can change the global demand, which changes the price in California. So we have to recognize we're operating in a global environment, global marketplace, but we have the little deviations that are caused by the technology changes, and the technology improvement.

I also want to mention for biomass, that's a very fuel specific, you know, biofuels are very specific and site specific, so the costs tend to be more specific in order to use that fuel source, and so the ranges in biomass costs are more dominated by the availability of the fuel and the site.

Geothermal, again, that's more stable and more resembles a fossil technology, something that has been around for a long time in the marketplace, however, we're starting to tap new geothermal resources that are a little lower quality, we're also finding that, again, natural gas comes to play when you're talking about geothermal because 40 percent of the cost of a geothermal project might be the well drilling, and well drilling costs are dominated by the competition between drilling rig prices that are being used for natural gas vs. geothermal. So, again, market competition comes to play in determining the cost of geothermal, to some extent.

Lastly, solar thermal, a few years ago we expected to see many more solar thermal projects, we had people -- entry level projects bidding quite low into the marketplace, and then we moved basically to have several of those projects fall victim to competition, and we saw that, in order to achieve what they needed to achieve, their cost had to go up. So we perceived, Black & Veatch at least perceives, that the price of solar thermal is increasing at this point in time.

What are the key drivers and are they unique to California? Basically my sense is that the key drivers are not unique to California. What is unique to California is that California has more of these renewable resources available here, and so at times those are competing with each other more significantly than they are in other places in the country or the globe. But the drivers tend to be basically technology development drivers, R&D-type drivers, commodity pricing, as I mentioned before, the big drop after 2008, the competitive landscape, and the margins that result from that, and then the site-specific things are the site-specific technologies. And then, of course, the incentive availability determines the overall characteristics of how that technology competes in the marketplace for the ultimate price and value. So, site availability and technology development will drive the long-term market, incentives will drive the short-term market.

What R&D effort could reduce balance of system costs? I would say that varies much by technology, but I see distributed generation impacting things much more so than it has up to now, and net zero microgrids, the impacts of AB 32, business rules that change the status quo, those are all things that are going to impact distributed generation in the ultimate cost and price.

I want to emphasize here, going backwards a little bit, but when you go from the costs, Black & Veatch's data, to a capital cost that more resembles a market cost, one of the biggest factors are the owner's costs, which can represent 15-35 percent of the project costs, and those include things like project development, interconnection, spare parts, owner's project management, start-up of construction support, taxes, advisory fees, owner's contingency financing, and there's a whole sub-list under each of those bullets, and so you have 40 or 50 things that can impact owner's costs, and they will affect the overall price, and that's why when you go out and poll developers on their project sites, they will have prices that vary quite a bit from the costs.

The last slide, what factors can change cost projections, I just want to point out that public policy is king, public policy impacts demand, and I just mentioned that policy in Europe could impact demand in the U.S. which impacts prices in the U.S., the overall market price. Changes in distributed PV will have the most impact in the near term, changes in technology R&D, net metering laws, community microgrid rules and regulations, net zero laws, all will change the landscape and move us towards a different competitive marketplace.

And that's it.

COMMISSIONER PETERMAN: Great. Thank you, Jon.

A couple of questions. I appreciate your presentation, although I would say policy is "queen."

[Laughter]

But policy is taking its time. So I just wanted to go to your second slide showing the capital costs and energy costs and I noted in the footnote there that you note that transmission cost and system integration costs are excluded.

MR. PIETRUSZKIEWICZ: Yes.

COMMISSIONER PETERMAN: And this is key question that the Commission is considering, about what are the all-in costs, and particularly we are concerned about the cost of integration, so I was wondering if you had any comments on that, and also I would be looking to the utilities to offer any comments they have about the range and integration costs they might see across different technologies. And also, related to that question, you know, thinking about the impact of the lower natural gas costs now on integration, we're using natural gas primarily as our integration resource now, and I was wondering if that's now, then, the lower cost of reducing integration costs, or if that's counterbalanced by the degree of integration that is now needed, which may be increasingly more expensive.

MR. PIETRUSZKIEWICZ: Yeah, I guess what I would say is, to answer your second question, the integration of cheap natural gas is helpful, and also the fact that we're only initiating the curve as far as integration requirements are concerned, is helpful, so we have some time to learn and we are learning along the way, and technology will develop and technology will change along the way, and begin to serve that marketplace as it evolves.

So I guess, as a personal opinion and not necessarily a corporate position or anything, I would just say that, in my experience, I think we worry a little too much about integration. I think it will sort of take care of itself as it all works out and there's some balance that occurs in the marketplace, and the balance between distributed and central generation is another key factor that will influence that. So I think there's a whole lot of things competing with each other, they all turn into market forces, and those forces will all determine what the ultimate things are that we need to do to accomplish integration and to pay for integration.

And then, what we learned in some studies I've been associated with recently is that business rules will have a lot bigger role to play as grid operators change their business rules in order to take advantage -- as somebody mentioned earlier, the idea that, let's say, natural gas plants might have the capability to do some integration things, but they might not be paid for those services today, so maybe we need to change the business rules, so we pay for those services, we take advantage of technology, and then that creates a different marketplace than we had before that. And so I think those are all factors.

I think, back to the first question with respect to including transmission cost, the reason that Black & Veatch doesn't include transmission cost upfront is because they are something that influences you downstream, and so if you have a 10-mile transmission interconnection vs. a 150-mile transmission interconnection, because you chose one site or another site, and you chose one voltage or another voltage, and you chose an existing substation vs. not having an existing substation, those are all factors that can influence you and increase the band of what we're trying to show as the cost. So we recognize that the utilities have a tough time because they have people putting projects in all of these difficult places, making the choices, but then there has to be a cost associated with that and it has to be individual and, again, another personal opinion, I think over time I'm thinking we'll get away from that specialization of pricing that, and that just in order to facilitate the massive number of projects that we need to move forward, we'll start moving towards more standardized costs and procedures, and a lot of people would find fault in that because of the deviation that creates; one project has a different cost than another, but it has the same price because you've created a market rule to do that. I just think we'll move there out of convenience over time to more standardize what the interconnection costs will be, make it more predictable, and make the marketplace more predictable. But I think that's a debate that hasn't been held yet.

COMMISSIONER PETERMAN: Thank you. And we just had -- I think it was last week -- a workshop on interconnection and thinking about how with planning we can address some of the challenges there.

I wanted to touch on financing costs. At the Governor's Conference on DG last year, it was raised by some of the attendees that it's more expensive to get financing, for example, for biomass facilities than, they felt, for solar PV. And the reasons raised were the financing industries', you know, comfort with the technology and factors like that. And I was just wondering if you could talk to that point, if you've observed that?

MR. PIETRUSZKIEWICZ: I would expect that to be true, and I think it applies to other technologies, as well. The faster a technology is moving, the more projects that are happening, the more experience that exists, the better the comfort levels are. And some of these issues get addressed and dealt with, and then the costs can come down because there's lots of competition. Bu there's a lot fewer biomass projects out there, there are a lot fewer geothermal projects out there, so I would expect financing costs and uncertainties associated with the degree of knowledge that's available for those costs, to be more problematic for those. So I think the faster that things are changing, the more projects that are happening, the more learning that has to go on, the more that facilitates a marketplace that operates correctly.

COMMISSIONER PETERMAN: Great. And just one more question, and then if Richard has any responses to the questions I've asked, as well. So on one of your slides, on slide 8, you touched upon margins that result from the competitive landscape, and I'm wondering if you have any information to share about relative margins across some of these industries, particularly relative to, say, natural gas facilities which have been with us longer.

MR. PIETRUSZKIEWICZ: I don't monitor the margins of specific things, but I would just remind us all that the ultimate margin of a project bidding into a private power marketplace is much different than the margins that are back at the entry level of the piece of equipment, or the individual commodity, or the labor, or whatever it is that are all the things that build up the price of that technology. So while solar PV module margins might be changing drastically, depending on policy and other factors that might not be the biggest impact at the end of that chain. At the end of the chain, it might be more financing assumptions and the things that the developer has to deal with to create the overall margin that's built into that project. So it's a very difficult thing to comment on.

DR. MCCANN: Yeah, just to comment on a couple of the questions. In terms of the integration costs, they are important by technology, but one of the first things that has to start is to understand -- have a clearer understanding of what the current integration costs are that are in the system, and that hasn't always been highlighted in the studies that have been done, and from what I've seen of current load following requirements that on the existing system are actually pretty substantial, so that the marginal increase is not as large as might be originally portrayed. And along those lines, the studies that have been done are showing steeply declining capacity factors for the fossil fuel plants, for example, on the combined cycle plants going from current 60 to 70 percent in California down to 40 percent. And that will greatly affect the cost of both just delivering gas-fired power, but also the integration prices that they might charge, they're going to have to be more reliant on capacity or fixed price terms in order to deliver those kinds of services, because they won't have the energy sales to maintain that. In addition, one of the red flags is what will happen with coal plants because they also showed steeply declining capacities down to 60 percent, and it's going to take major capital additions in order to allow coal plants to run at those low capacity factors, and if that happens, I think there's going to be a greater impetus to retire those coal plants. That's going to change your whole system, and that question really hasn't been addressed either in those sorts of questions, and then there's also a question of gas deliverability to natural gas plants, can you deliver gas in the short space that you need to deliver given our current gas distribution system, and that's another question that we haven't really addressed in the integration component.

In terms of transmission costs, you might be looking for zones, zone pricing in terms of distance, or something along those lines, but, as Jon mentioned, transmission costs are really highly location-dependent. And I think that that's -- having a clear understanding of the transmission costs and being able to tell developers and tell utilities where to focus based on those might actually be a really important piece of information that comes out of the Commission.

And then, finally, just talking about the margins, one of the things is that we can look at other industries like aerospace and computer technology to look at how price trends have continued over time, the silicon panel price trends follow what happened with memory chips, and so we can expect similar types of experiences. Now, the question is, will we get similar technology leaps like we did with memory chips and panels? You know, our hard drives are going to be gone in five years. What can we expect? What can't we see down the road that's going to happen? So I think that's going to really affect those.

COMMISSIONER PETERMAN: Thank you for those comments, in particular some of the comments you made around natural gas plants. At our June 11th workshop, we're having a panel on natural gas plants for integration, and particularly looking at some of the issues related to maintaining Line Pack, and having the available fuel if you're having these reduced capacity factors.

DR. MCCANN: So I'll make a pitch for Katie Elder to be on that panel, who is my colleague at Aspen, who particularly -- I raise that issue particularly for Katie, and she has really looked into this question. I think she will have some useful insights into that.

COMMISSIONER PETERMAN: Thank you. Well, I know Ms. Elder to be an expert in all things gas, and so I will look forward to her involvement. Thanks, Al, those were all my questions.

MR. ALVARADO: Okay, I have one question. We've discussed the variability of some of these key cost drivers, which ends up resulting in, in some cases, a pretty wide range of levelized cost estimates. Is there any sort of, well, I guess in one part, any key drivers and possibly any policy recommendations that might sort of tilt the field so a developer would end up realizing some of the lower cost ranges -- for any investment decisions?

MR. PIETRUSZKIEWICZ: Well, clearly there's always policies that can be implemented to affect anything, so if we go through my long list of owner's costs, you have things that impact property taxes, you have things that impact the cost of financing, you have things that impact the initial capital costs, so there's a lot of policy changes that can be made. That's part of the complexity of evaluating costs, and evaluating changes in costs. We indicated that the wind tax credit is going to go away and what is that going to do to the marketplace? And what is that going to do to demand? And what is that going to do to the costs? So again, it's an easy and a difficult question to answer because there's so many layers involved.

DR. MCCANN: We think about factors that are at the hands of the government control, the technology cost itself is pretty much out of the hands of the State and Federal Government at this point, most of the research has been done -- I mean, there's going to be some underlying research that may lead to particular technological leaps, but the steady trends are basically -- they're already being pushed by the private market. And to the extent that there is a procurement, a mandatory procurement of renewables, that will drive that. But the three levers that I can think of, in particular, are of course taxes and tax credits, which we've talked about and I'm not going to go into depth on those because everybody pretty much knows about those, although there is the question of treatment of property taxes and then there's also an additional question about sales tax questions, and that really affects the sales tax and it particularly affects local governments.

The second one is about environmental compliance costs and, so, for gas plants it's mostly air quality issues, but for the renewables, it's what you have to do on the land that is really the footprint effect, the mitigation, where you're putting those particular plants, and relative to the rest of the power infrastructure. And so those particular environmental compliance costs may -- it may require some deep review of those costs, of where you're trying to head with various issues. And ultimately there's also a tradeoff in terms of the environmental goals, there may be a tradeoff in the environmental goals that we're trying to achieve in different ways. It's unlikely that we can achieve all of the goals that we want with putting solar PV on every rooftop, that's just not going to work. So we're going to have to look at other sources and think about those tradeoffs.

But the other thing that really hasn't been touched on much, but is actually really quite important, is the terms of the PPAs, the debt, as I mentioned, for example, we saw the debt terms are actually quite --

really affect the final costs for these projects. Those are actually driven by lenders' perception of what the contracting terms are, and what they can expect to get out of the power plants, power plant developers. So that's just one example and I think that having a close review of that in terms of how you want to encourage ultimately lower owner costs, as Jon has mentioned, being very cognizant of that, I think, is really one of the key components of how the Energy Commission and other State agencies can affect the cost trends.

COMMISSIONER PETERMAN: Well, I think we find ourselves in a very unique position of actually having time for questions for our panelists, as well as comments. So I'd like to suggest that, if there's anyone first here in the room that either wants to ask a question of the panelists, or wants to comment on any of the questions that I raised -- Steven Kelly is going to stand up, go for it -- wants to comment on the questions I raised, or just any of the facts they just heard, welcome.

MR. KELLY: Thank you, Commissioners and panel. Steven Kelly with the Independent Energy Producers Association. And I have a question about the comparison of costs, the capital costs, across technologies. And I appreciate that graph had showed the comparison across the renewable technologies, and then one of the technologies was the gas, and I recognize in the footnotes you said that we're excluding the integration costs of transmission. But my question was, how are you proposing to treat fuel costs? Renewable investment is long-term, as you had indicated, 25 years, and I was curious to know how the long-term fuel costs are used in the comparisons across the various technologies.

DR. MCCANN: In the cost of generation model, we use the price forecasts that the Energy Commission produces for natural gas fuel prices, but we also have, again, used a range there, a high and a low range --

MR. KELLY: Is that going to be reflected in the capital cost picture that you present there?

DR. MCCANN: Jon presented that picture of their costs, and I don't know -- I can't answer for him how he included, but I believe that he probably included full operating costs in that cost comparison because he was including a dollar per megawatt hour comparison.

MR. PIETRUSZKIEWICZ: Yeah, so what I would say is that every quarter Black & Veatch updates its market forecast and in that market forecast, we have all the fuel prices and we update that, so then when we do a levelized cost of electricity calculation, we do it with whatever the fuel forecast is at that point in time. And as things drop dramatically like, let's say, between 2008 and now, there's been, for example, gasses have a huge decline and most people are predicting a lot flatter gas prices for the future than they were predicting in, let's say, 2008. So those kinds of analyses and decisions get factored into these calculations. But, again, those are assumptions and those are assumptions that get reviewed at every level, and it depends on who is making the calculation what assumption they want to use.

MR. KELLY: But the presentation of capital costs will include kind of the avoided fuel costs over a long term, for like wind vs. natural gas?

MR. PIETRUSZKIEWICZ: Well, capital costs do not include fuel costs, levelized cost of electricity calculations do include fuel costs. So in my charts, there are different columns for those things.

MR. KELLY: Okay, thank you.

MR. KLASSEN: I'm Rusty Klassen, Tensleep Advisory. My question follows on to this, but at a slightly different level, which I appreciate your willingness to consider, and obviously you have. And that is the question of trade policy in relation to fuel cost. There is an incredible sort of corona of optimism around gas cost, which myself, I don't find supported in any history. And so, with China and India developing an appetite for everything we have demonstrated as useful in ordinary life, I wonder how you're going to reflect that as a financial projection in terms of how the United States trade policies restrict the competition for this presently low cost asset, in relation to the question of how we price the static production capacities of solar and other sort of long-term reliability elements.

MR. ALVARADO: Well, I think throughout the whole IEPR, we do engage in analysis of very different components of the energy system and one will be the fuel sector, and I'm not the fuel expert here, but I know that they have evaluated numerous world factors that will be reflected in the price of natural gas, at least. And for the cost evaluation for generation, we are one of the users for those forecasts. So we at least do try to capture some of those ranges of uncertainties associated with the fuel costs.

COMMISSIONER PETERMAN: I would also just comment quickly, to follow-up on Al's point, before you go, because I also work on natural gas issues here at the Commission, that LNG potential exports are considered, but to your point, some of those long-term implications in terms of some of the trade policies have not, and we're actually coming out with the Natural Gas Trends Report and Forecast Report in the next week or so, which will explain some of the issues that we've considered, but I have to give more thought to your question, sir, I think it's an interesting point you've raised.

DR. MCCANN: Oh, I was just going to add that, in the cost of generation model, is what we did previously was developed a range based on forecast, or previous forecast errors, so that we were basically trying to bound based on our past experience where these forecasts might deviate from what we had done before. So then, in some ways we were actually capturing a large range of that uncertainty.

MR. PIETRUSZKIEWICZ: I guess that was the point I wanted to make is that, what we've learned over time, sometimes more so than other times, is that no forecast will be perfect, all forecasts have error, all forecasts therefore need to have wide ranges and wide bands based on some set of assumptions, whether it be historical assumptions, or whether it be history that's modified for some reason, whether you can try to predict things that have not happened before than might give you a wider band, even, than you've had historically. So I think it's just important to recognize that there's uncertainly involved in everything we do.

COMMISSIONER PETERMAN: Great. As the next person to question comes to the podium, I will just say to the panelists that, when we wrap up this panel, I will ask you if you have any explicit recommendations for the Commission now. You've touched on some generally in your presentations, but wanted to give you that opportunity. So now we have Valerie Winn with Pacific Gas & Electric.

MS. WINN: Hi, good morning, Commissioner Peterman. I had a few questions for Black & Veatch on slides 3 and 4 of their presentation. And I was curious as to -- I know this is based on projects that you have been involved in and I'm curious as to the geographic dispersion of those projects. Were these projects in California? Or are these projects nationwide?

MR. PIETRUSZKIEWICZ: These charts primarily reflect experience in the Western United States, and they would have to be massaged and modified to be very very specific to California. But they are generally reasonable for the Western U.S. and, when we do it more geographically specific, we don't just use the projects in that geography, but we use projects outside of that geography, and then we modify it to reflect what we know about projects in that geography. So if, let's say, I had five projects in California and 100 projects outside of California, I might still use those 100 projects from outside of California, but I would adjust them to move them into California.

MS. WINN: Okay, I was curious about the capacity factor that you had assumed, particularly, for wind. They seem a bit higher than what we're generally seeing in California at this time.

MR. PIETRUSZKIEWICZ: Yeah, I guess there is another thing that's going on with wind, is that overall the average fleet capacity factor for wind is dropping around the globe. But technologically, the cutting edge technology is for wind turbines that can get more out of less, and so you are starting to see some projects with increased capacity factors, so I recently saw a financial analysis for one that had a 50 percent capacity factor. And you know, that's beyond the range that I show on this sheet, but that's an example of what's going on. Similarly, let's say, you know, I'm from sort of the Bay Area, mostly, and over there there's Solano wind turbines, and in Solano, five or 10 years ago, there was a fairly small area you could put wind turbines, and that was due to the wind that was available, the technology that was available to achieve reasonable economics. If you went and evaluated projects at that exact site today, you would probably go beyond the boundaries of that site to the entire county, instead of just the site that you had, just because of technological change. So it's interesting.

COMMISSIONER PETERMAN: Valerie, before you ask your next question, let me just have a follow-up. So are we seeing the average capacity factor drop globally for wind because of the wind resources, in terms of expanding into lower class wind resources, or what's the reason for that?

MR. PIETRUSZKIEWICZ: The majority of projects have used the very best sites, and so now we're picking sites that are a little less optimum, and we're also picking more risky sites, so maybe you put a project in a location where you expect something to happen that you don't exactly get the results that you originally expected. So it's a combination of factors, but I think, in general, Lawrence Berkeley Labs is the one that has the statistical data for the country that shows that the national average is decreased.

DR. MCCANN: And you're going to see that, by the way, just with geothermal, same thing, and then as biomass develops, you're going to see an exhaustion of the prime sites and a move into the lower quality sites as you move along, and solar eventually will reach that point, as well.

MS. WINN: Okay, thank you very much. I did actually -- I think Black & Veatch had also noted the owners' costs are generally about 40 to 50 percent of the total project cost, and I just wanted to make sure that the Commission was aware that, you know, when we have our renewables solicitations, we don't get costs from developers that are broken down on those lines, we only get an all-in cost, generally, that is given to us, and so we have no ability to influence that, or to consider those costs in our evaluation.

You also asked a question about the transmission cost and I know we've had these discussions before, but generally PG&E has been very supportive of spending maybe a little bit more on transmission and working on getting the system that is maybe a little bit over what might be right size, because we really see some benefits there in getting price on price competition from the renewable generation, and that's really where a large amount of our customer dollars are going to be going is to generation, and not necessarily transmission, so spending a little more on transmission could actually get us some benefits in reducing customer cost for generation.

You had also asked about biomass projects and their ability to get financing. Our experience has been that they're challenged in getting financing more because of the reliability of their feedstock and their ability to lock that up in contracts. Generally, we're seeing that they're not able to -- they might want to do a 20-year contract, but they're not able to lock up a fuel supply for that entire period of time.

And then, lastly, on integration charges, you know, I think the jury is still out on what those costs will actually be, but I think right now we've seen a range of analyses that might say it's anywhere from $7.50 per megawatt hour for wind and solar up to, say, a high of $15.00 per megawatt hour, and I think we'll learn a lot more about what those costs might be over the next few years.

COMMISSIONER PETERMAN: Great. Thank you very much. I'm sure you'll be providing comments at various workshops, but if you can note some of those integration cost ranges, as you see them now, that would be great.

MS. WINN: Okay. Thank you very much.

COMMISSIONER PETERMAN: A question over here, and then I'm going to ask that we then see if there's anyone on the phone who has a question. Not yet? Okay, great.

MR. KIM: Daniel Kim with Westlands Solar Park. Just wanted to ask whether or not the cost modeling is going to take a look at land prices as a kind of major factor with respect to -- I think it was Chart 8 or 9 -- that highlighted the owner's cost percentages.

DR. MCCANN: We will be looking at land prices in the cost estimates, but even for solar projects, the acreage that's involved, the land costs don't have a huge impact on the final prices because the prices we're typically looking at are $3,000 to $10,000 an acre, and those just don't -- when you're looking at 3,000 acres, or 4,000 acres, it's not a huge component of the project cost.

MR. KIM: I would beg to differ on that price assumption with regards to private lands, and especially agricultural lands in the Central Valley. You're seeing much higher numbers, given the kind of move to projects going from public lands to private lands, particularly these so-called marginal farmlands, and it's creating that kind of speculative bubble that we saw, I think, earlier in mid-2000 with regards to some of the Federal lands that were being put up for sale.

DR. MCCANN: Yeah, we're -- the projects we've looked at, ones in the desert and on the Central Coast, which is not the Central Valley, they've typically been around about $3,000 to $6,000 an acre there. We haven't looked at, for example, what would happen in Westlands. And if you have any information, we would probably want to look at the Central Valley costs, as well, because we do want to look at some of the regional differences in the various projects because there are tradeoffs in project costs by region.

MR. KIM: And especially when you get to the lower kind of substation size projects that are typically less than 1,000 acres, the land price becomes a significant factor determining the economic viability of being able to compete in a very competitive PPA market.

COMMISSIONER PETERMAN: Yes, one final question here in the room and then we'll turn to the phones and then to the panelists for final comments.

MR. PINGLE: Hi. Ray Pingle with Sierra Club. Good morning, Commissioner. First of all, we'd like to say that the levelized cost of energy studies that the Commission has done, I think, are extremely helpful, and if financially feasible, it would be very helpful to do those on a more frequent basis so the data is kept more current. And I'm pleased to hear that you're exploring doing cost LCOE studies on various distributed generation technologies of various sizes. I think that would be very helpful.

In addition to that, in the most recent study, you looked at the cost of basically a gas-fired peaker plant, so a different technology applied in a different way. And it might also be helpful to look at some costs of other technology, storage technologies, and so on, that could meet that need, so we could do a comparison.

And then also, when we consider the costs of integration, you know, under SB 17, all the IOUs are developing Smart Grid deployment plans and part of the components of those plans include integration technologies, more computerized automated management of the grid, to do balancing using demand response, the better forecasting for resources and so on, so to some extent some of the integration costs are in a sense some cost because they're already required, and they're required for many many reasons other than just supporting renewable, to support other technologies. S o I just think that's something that should be considered when considering the real cost of integration.

And then, one finally question I had for Mr. McCann was you had mentioned about how capacity factors are actually decreasing for some of the coal-fired and natural gas-fired, and I was curious as to what some of the factors are contributing to that. Thank you.

DR. MCCANN: Well, the primary -- these are actually mostly coming out of studies that are being done looking out to 2020, and they're studies done by WECC and done at the PUC, for the PUC, and in those studies it's the increased penetration of renewable resources that are a must take, and it's making it so that those fossil resources become dispatchable, so that's really what's driving that -- the lower capacity factors on those plants.

COMMISSIONER PETERMAN: Any questions on the phone? And then one more question in the room.

MS. GREEN: Hello, could you please state your name first? Hello? Hello? Do you have any comments for us?

COMMISSIONER PETERMAN: I think we'll go to the question in the room, then. Go ahead.

MR. SILSBEE: Thank you, Commissioner. I'm Carl Silsbee from Southern California Edison. Could we get page 3 back up, the one that showed the capacity factors? I wanted to talk about that in a minute. First of all, we've been very supportive of the CEC's ongoing work in supporting the cost of generation modeling and I think it's something that is very useful for you to continue to look at in the various IEPR cycles. It's a good touch on what the data are currently. At the same time, we've been somewhat critical, not so much of the work, but of our fear of how it's being interpreted. And I think it's very important to realize that what you're seeing in the numbers is not a beauty contest that says, "This is the right technology because it's cheaper than others." We have to look at this in the sense of an overall integrated resource plan, and there are a lot of interactions among different kinds of resources. So if we looked, for instance, at the natural gas CT, you can see a capacity factor of five to 50 percent -- I hope we don't get to 50 percent, but if you divide the capital cost by the capacity factor to get an idea of what the dollar per something is, it's a range of 10:1. And that doesn't say that a CT is cost-effective if it's running at five percent and not cost-effective if it's at 50 percent, obviously. So we need to be very careful when comparing capacity value vs. energy value, for instance, and levelized as energy metric.

More significantly, for instance, as we see a build-out of solar thermal and solar PV in our system, what it's doing is it's shifting the net load peak. That is, the customer load minus intermittent renewables until later in the day, and it's changing the whole reliability perspective. And just diminishing returns, solar them becomes less valuable because it's just not delivering as much later in the day. And so we need to be very mindful of those kinds of considerations. So it's not just the total cost that you mentioned earlier, but it's also a total value that's important for us.

COMMISSIONER PETERMAN: And thank you, and I thank you for acknowledging that both of those are shifting. There is some good work coming out of Lawrence Berkeley National Lab by Andrew Mills, particularly focusing on this issue of, as you get to higher levels of integration of solar PV and solar thermal, the declining potential value there associated.

MR. SILSBEE: Thank you.

COMMISSIONER PETERMAN: Let's turn back now to the panel for any final comments.

DR. MCCANN: Yes, thanks. I think that looking at recommendations for the Commission to focus on, I think I would -- it's going back to some of the levers that I had mentioned; one is focusing on -- getting better information on transmission costs over wide ranges, so that there was -- in the 2007 IEPR, there was embedded in the IEPR was some information about transmission costs that we were able to convert into our 2009 model in order to try to get some estimate of cost. I think that doing something along those lines that gives us a more defined or refined estimate of how transmission costs vary across regions of the state, what might be helpful in terms of policy planning and where the Commission might recommend focusing on those sorts of things.

The second one is, on the DRECP, which the Commission is running, is focusing on the tradeoffs in renewable policy vs. local environmental conditions, and that's something that’s very salient to the Commission, it's -- there are a number of other agencies that are involved in that discussion, and I think that the Commission would be well set to really plunge into that issue and have good hands on interaction with that, and think about how that's affecting the renewables trends over time. And the third area is looking at terms in the PPAs, and how that affects the ultimate, the final costs that you see that are paid by ratepayers, and I think you're going to be talking about procurement issues in the next panel, and that’s probably asking those sorts of questions of those people, it might be particularly helpful.

MR. PIETRUSZKIEWICZ: I would just suggest that we dwell on uncertainty a little bit and, as we model these things, we'll probably be getting more sophisticated in how we deal with uncertainty, of the multitude of variables that go into these calculations, and you know, I can't predict what the outcome will be, but I think dealing with it, the analytics more carefully, we'll tighten our bands up and make us a little more certain in what we're trying to do.

DR. MCCANN: I just would follow-up to even say that maybe we need to think about treating -- looking at our insurance products with uncertainty, because we'll never get it so certain that we'll know what the answer is, so we've got to ask the question -- we don't know a lot of things and we aren't going to know anymore, and now what do we do?

MR. ALVARADO: I would like to just emphasize transparency. One thing I found very difficult when I looked at different levelized cost of generation studies, is it's really hard to compare one cost estimate for a same technology next to another and the devil is really in the details. So I think, as we move into this next phase of calculating levelized cost, we really need to drill a little bit deeper down into understanding what those key variables are, especially if we want to compare one study to the next.

COMMISSIONER PETERMAN: Great. Thank you very much, Al, Richard, and Jon, appreciated the discussion. We're going to break now for lunch. We'll be resuming promptly at 12:45. Thanks.

(Recess at 11:43 a.m.)

(Reconvene at 12:48 p.m.)

MS. GREEN: Our second panel of the day will be moderated by David Vidaver and we don't have any presentations from the panelists. Go ahead, David.

MR. VIDAVER: Thank you, Lynette. Good

afternoon, Commissioner. I wasn't here this morning. Are we letting the witnesses introduce themselves and make introductory statements if they so desire?

COMMISSIONER PETERMAN: Our invited guests may indeed --

MR. VIDAVER: I contemplated using "perpetrators," but….

COMMISSIONER PETERMAN: -- if they would like make a couple minute opening statement, we've got about an hour and a half of for this panel, and so I encourage you to make some opening remarks, and then get into a lively discussion. Thanks.

MR. VIDAVER: Mr. Lewis?

MR. LEWIS: Well, good afternoon. Thank you very much. My name is David Lewis. I'm Director of Renewable Transactions for Pacific Gas & Electric, and in this role my team manages a lot of the solicitation efforts through the RPS requirements, so we negotiate a lot of the transactions.

And for some brief opening statements, I just want to say that I'm probably going to echo a lot of the earlier comments from this morning's session in that, when we look at renewables, I think it's very important -- and as I looked over the questions for this panel, it's very important to distinguish between the separate elements that we're talking about -- price, cost and value. And those are completely different things, at least in my mindset and certainly how our utility approaches those different variables.

In terms of price, you know, our contracts are structured on a dollar per megawatt hour basis, that's the revenue stream that the PPA gets for delivering energy to us, we only pay for what we get. And it's important to understand that, yes, price on some of these contracts have gone down, but that is only one factor and it's not kind of the end all be all because what's also equally important, if not more so, is costs. And costs have a lot of different elements associated with it. The price is an element of cost, but there's cost to the developer that go beyond just the traditional kind of paying pricing or component pricing pieces of it, which a lot of people seem to be focused on, but then also there's the other soft costs associated with these transactions, too, for the developer, which in turn drives their price.

Similar to the utility, we also have cost concerns, as well, it's not just the price that drives our cost, but there's other elements of it, as well. There's transmission, there's integration costs, etc. So it's important to understand that price is just an overly simplistic metric to look at when comparing a lot of different deals and a lot of different transactions.

And so, our perspective in how we look at these deals is really to concentrate on value of these transactions, which incorporates price and the cost elements, but also incorporates a lot of the other attributes associated with these products -- environmental attributes, project viability attributes, credit attributes, you know, adherence to terms and conditions, these are all things that we consider when we're looking at a transaction. So we don’t just get focused on price and cost, but look at the total value that the deal represents to us, and that has a lot of nuances to it, and a lot of different elements that are hard to exactly quantify, so they are a much more qualitative effort.

When we look at the total package, then, we have to consider what is the value that these deals represent to the company, as well as to our ratepayers, and that's how we distinguish these, as opposed to focusing on an element of cost decreasing, or prices decreasing.

COMMISSIONER PETERMAN: So just a quick follow-up question on that. In terms of how you're -- I'm thinking of the best way to phrase this -- in terms of how your procurement is considered than at the Public Utilities Commission, in terms of your ability to recover costs, is that entire suite of attributes you just discussed a part of that deliberation?

MR. LEWIS: Yes, in part of our filings we mention all the different attributes associated with the transaction, so it's not just a pure dollar number, but also the overall value that it represents, both the kind of hard dollar number, as well as a lot of these other soft attributes.

MR. WALSH: Good afternoon. Thank you for having me here. My name is Bill Walsh. I'm the Manager of Renewable Procurement at Southern California Edison Company. My group is in charge of all renewable procurement coming out of Edison, including our large solicitation, as well as my group manages all the Feed-in Tariff programs such as RAM and SPVP.

I don't want to repeat a lot of things that Mr. Lewis at PG&E stated, I agree with a lot of it, a lot of our selection is based on value, I think focusing on solely price as a mistake; although it can be a large driver in terms of our procurement decisions, it is not the only driver, there are still other costs and benefits associated with different types of projects. And as long as we're measuring those correctly, you're pretty much on the right path. I will say, when you're talking about procurement, in general, there currently -- if you are a certain size and a certain technology, you have five procurement options, and within those five procurement options, there are varying degrees of how we measure the value of the project, or, if at all, because some of them are essentially administratively determined pricing under the procurement program.

So, in general, when you're talking about procurement, it's important to know which program you're under, how do we measure value under that program, if at all, and then determine what is the best selection to make. In our opinion, most of the procurement should be driving towards something that measures all value, including contract price, integration costs, transmission costs, along with the benefits that are associated with the different technologies. Thank you.

COMMISSIONER PETERMAN: It's interesting hearing you both talk about value, and we'll touch on this some more, but it was a key topic in our benefits workshop, talking about all in value, and there were some disagreement, I would say, amongst utility representatives about what other value -- what attributes should be considered into that mix, and so I would posit that you're considering value, but not necessarily all of the environmental values associated with certain types of generation, like ones that came up in the past workshop was the fire hazard reduction potential, for example, with biomass collection, and that's not something that is considered a part of the value.

MR. WALSH: I think that's correct, we're more focusing on the costs and benefits associated with energy procurement, so out to serve our energy and capacity needs, as well as making the RPS goals.

MR. LEWIS: I think what's really important to understand about value is it's very difficult to actually quantify it, so when you take something like fire reduction, yes, it has a benefit and we consider that, but what is that worth? Is that worth a dollar a megawatt hour, ten dollars a megawatt hour, and then how do you say that the value that we've gotten exceeds that presumed cost? So that’s what makes it very very challenging with value.

COMMISSIONER PETERMAN: Makes sense. Jim.

MR. TRACY: Good afternoon. I'm Jim Tracy. I'm the Chief Financial Officer for Sacramento Municipal Utility District. We appreciate the opportunity to come and present the municipal point of view, at least SMUD's point of view, on this.

I think my comments would revolve around the policy goals of the State vs., say, the policy goals of SMUD. I think SMUD probably has somewhat of a subset of the State's policy goals. When we look at job creation, I think from our Board's perspective, having the lowest rates that we can possibly have within the community to attract all businesses, is really the primary goal, as opposed to focusing on a particular sector like the green jobs.

Of upmost important, then, to our Board is overall rates, so having a renewable portfolio that is low cost is important; probably secondary, but almost as important is whether that portfolio is going to produce a stable and reliable power supply. Some of the other objectives, you know, that the State may have, may not be as important for SMUD, and so the overall Integrative Resource Plan, which my group produces, would really reflect SMUD's primary goals as stated by our elected Board of Directors.

COMMISSIONER PETERMAN: Well, let's take -- we'll mix it up a little bit -- Randy Howard on the phone next with LADWP.

MR. HOWARD: Good afternoon. Can you hear me?

COMMISSIONER PETERMAN: Yes.

MR. HOWARD: All right, well, thank you for allowing me to participate by phone today. I was hoping to be there, but it just didn't work out with some of the flight issues and the time.

So I think, very similar to the other speakers so far on this panel, LADWP really looks closely at the cost considerations as to how we procure, but we do value a little differently. You have to look at what are your existing resources, what are your other mandates, and what we've attempted to do in our Integrated Resource Plan is look at all of the various mandates, the timeline in how we sequence those mandates, and in the procurement of renewables, how can we reduce some of the costs associated with the multiple activities so that renewables, on themselves, aren't the focus alone, but they might help us in achieving a reduction in our divestiture of our coal plants, or as we transform our once-through cooling, can we ensure that those repowered facilities are going to accommodate the intermittency of renewables. So we try to spread the cost appropriately across the various activities, and then we have to come back to what really are we going to be able to pay for based on the rates that our governing authorities are going to approve. And so we come back to what are the technologies and the activities that we can do.

So similar in how we walk through evaluation. Everything we do is competitive, we don't do a sole source negotiation, so they're quite transparent in approach, and the way we would initiate is we also look at projects and determine how can we add value to a developer's project, is it -- can we do a pre-pay contract? Would that bring in our lower cost to funds pre-paying, reduce the costs or the risk of the project? Can we utilize our land resources or our transmission system a little better to reduce the cost or bring greater value to our ratepayers? So we look at a number of the elements, we certainly don't just take it on the face value of a proposal.

COMMISSIONER PETERMAN: Thank you.

MR. SIMON: Hello. My name is Jason Simon. Thanks very much for having me here today. I work for the RPS Group at the California Public Utility Commission. I work on primarily large-scale utility initiative on the procurement side and also the policy side, so I do interface regularly with, say, these two fellows over here, David and Bill, and we look at what their, I guess, solicitations are on a regular basis, on the annual solicitation side, to what Bill was saying on the RAM side, and the various solar PV programs that utilities have.

I guess the conversation is revolving around how these products should be valued, and the CPUC has taken the approach that we are looking at the value of a project and not the cost. The cost is actually a component of how value is measured, so the way, at least, that we know that PG&E and Edison are looking at projects and ranking projects, at least in their annual short lists, they are looking at the total value that is associated with the projects, and not necessarily the costs.

Obviously, because this is a market that is based on supply and demand, and not on cost, we look at market metrics, we don't look at cost metrics. Cost metrics, too, obviously can be nebulous, looking at a levelized cost value is very different from region to region, from project to project, and to some extent very difficult to update in a very timely fashion.

So the Commission is looking at least cost best fit reform, which I think is what Dave and Bill were alluding to, from the perspective of what values do you add that are incremental to the least cost best fit valuation. And we do have a consulting initiative happening right now, which we are contracting for, and is going to be looking at the different types of values that are associated with different types of technologies and, obviously, aligning our initiative with our Long-Term Procurement Plan because, at the end of the day, it really boils down to what are longer term system needs, which really will identify what the values of a lot of these different services are for a lot of these different projects. And sitting on my right here is Brendon, who we are actually working with on the Cost Containment Initiative, which is actually going to deal directly with some aspects of least cost best fit.

COMMISSIONER PETERMAN: Great. Thank you, Jason. And I think you just, in mentioning the term "least cost best fit," you know, you've touched upon perhaps a challenge for those of us who are not a part of the PUC's procurement process, that positioned with that phrase, "least cost best fit," you know, you'll assume that "least cost" is really the primary focus. And there has been raised by various parties at workshops that they're not sure where the best fit component comes in. But, from hearing from you, as well as from the other Investor-Owned Utilities on the panel today, it seems like there is a movement towards having the best fit be the dominant driver, if you will. So I wonder if you could speak to -- you mentioned cost as a part of that value, but is it the majority consideration?

MR. SIMON: Well, you know, obviously everybody on the panel could speak to this, but I would say that when we say "least cost" we probably mean more cost-effectiveness, so we're looking at the cost-effectiveness of a project relative to what the portfolio needs for the utility, and relative to what the portfolio needs are at the system level at the California ISO. And that's something that we actually have to take into consideration when we actually look at a Cost Containment methodology, is we don't want to bite off our nose to spite our face, and implement a cost gap without considering the cost-effectiveness of the program.

And to obviously elaborate on your question, you know, what is the "best fit" portion of it, that would be, you know, what the utilities determine to be what the best fit is for the project, based on their portfolio needs, based obviously on the time that the project is coming on line, with regards to the compliance targets that obviously have been implemented by the Commission through SB 2, and obviously whether or not they need more baseload vs. more peaking in our portfolios, and obviously things like that.

MR. PIERPONT: Hello, I'm Brendan Pierpont from the Climate Policy Initiative. So just a quick introduction of our organization, we're a policy effectiveness, analysis, and advisory organization, and so our mission is to look at kind of implemented policy to see how well it's performed, and as Jason mentioned, because of the requirement in the 33 percent RPS that the CPUC put together a cost limitation for the policy, I thought it would be timely to look at what other states had done in implementing Cost Containment.

So just a few sort of high level lessons that came out of this exercise. First is that, even though some states try to use Cost Containment to kind of make their policies more cost-effective, it doesn't really seem to be the case that it actually does that, it functions more as an insurance mechanism when it does work, it's kind of a release valve on the policy stringency when costs are higher than some threshold that's expected.

And implementing these types of things comes with tradeoffs, so you're trading off the kind of ambition of the policy, potentially the cost effectiveness some states have used public contract level price caps, or some sort of price signals and, then, in a number of cases, those that have been interpreted by the market more as a price floor than a price ceiling. So there are just a few little cautions in kind of how you design a cost cap for a policy that we've seen from other states' experiences, that we think might be relevant for California implementing similar. Thanks.

COMMISSIONER PETERMAN: Brendan, thank you for that. In addition to the Cost Containment work that the Public Utilities Commission is doing, the 40 plus public utilities that are also part of the RPS also have to develop their own Cost Containment measures, and so these types of insights are valuable.

I wanted to acknowledge that I've been joined on the dais by Commissioner McAllister, so welcome. And, David, I'll give it back to you. I would like to hear some answers to that first question, though, now that we've done some intro.

MR. VIDAVER: Now that we've talked about value being more important than cost, let's just go back to offer prices, which don't necessarily reflect --

COMMISSIONER PETERMAN: We already had the value worked out -- no, it's good to bring it in.

MR. VIDAVER: We're going to get back to value at some point here and how it's determined for individual projects, but let's note that offer prices and levelized costs, or costs of development, don't necessarily mean the same thing. Over the past decade, a lot of people, investor-owned utilities included, and I imagine some of the Munis, have said that the drive for renewable energy at a breakneck speed has created an environment in which sellers have some sort of market power, and that estimates of costs of development were less than valuable because you weren't seeing those in RFOs. Now, we have a situation where we have -- I think it's 3.8 million gigawatts in the ISO queue, and the utilities are approaching 33 percent, at least under contract if not in real procurement. Is the market for renewable energy in California now competitive? Have offer prices come down? Have then come down more or less for different technologies? And I realize this is a very sensitive area and you're probably not going to be providing fourth decimal place answers, but any light you can shed on whether markets for renewable energy are now competitive, and what the obstacles you see in the way of lower prices? And we could probably take it in order, unless we have volunteers.

MR. LEWIS: Sure. I'll go ahead and give a shot with that one. Certainly, we've seen that the market is competitive and we've seen a tremendous growth in the number of responses to our solicitations. We've seen that prices for the winning bids have come down, but I mean, I think it's important to understand the earlier panel, as well, that we are still seeing a tremendously wide range of pricing in between kind of the winning bids, and some of the other bids that just participated in the solicitation, but may not be selected. But I would characterize it generically that prices have come down. Certainly, I would say I think for fewer technologies more than others, and solar PV has come down, but if you also look at some of the other kind of cost elements to this tremendous divergence in the bids that we receive is very interesting, and that's really what gets to the cost side -- what are people assuming when they're putting in their price? And it's very hard to disconnect those two because you have to understand what are those underlying assumptions. And macro level discussions about solar PV pricing will translate into a price reduction is only one element of what makes up that price, finance and cost, etc., the length of time with which it takes to develop these projects are also an important factor to consider, and can drive and change pricing.

And just for example, just last week the new tariff that they have on solar PV pricing, what ramifications is that going to have? So I think, yes, we've seen the trend go down, but there is so much more uncertainty in these markets revolving around a lot of different aspects of it, that it's hard to say whether that trend will continue or not.

COMMISSIONER PETERMAN: And just a quick question, David. Valerie touched on this a little bit, but in terms of the information that you get, then, from project applicants, do you get information on their assumptions? Is that something -- I'm just trying -- how do we get you the more information that you need to realize what's the best value?

MR. LEWIS: It would be really nice for me to negotiate a contract if the developer gave me their pro forma and I know what their return was, but unfortunately it doesn't work that way, so we take the best bids that we get in, and we analyze them against its value equation, and we select the best winning bids that we can and we negotiate hard to get the best value that we can. But a simple assumption -- and I'm a finance guy by trade -- so a simple assumption about, as you saw on some of the earlier presentations, just about capacity factor for a project, if you assume a 30 percent capacity factor vs. a 40 percent capacity factor for a wind project, you can dramatically change the price that you believe it will take to win, and we just don't have access to all of that information, although it would be kind of fun if we did.

COMMISSIONER PETERMAN: And one other question, historically we've looked at the market price references to get a sense of how renewables are comparing perhaps to the dominant technology, but with gas prices coming down, if we were going to have an MPR now, what would that be? You know, how different would that be from the 2009 value that we've last observed?

MR. LEWIS: Oh, I don’t really have all the detail on that, but certainly, I mean, if you look at just the general power market, it's decreased so dramatically it would be interesting to see where that is. But once again, and we've touched on it before, what's your 20-year assumption, as well, too. So that's a key piece of it.

MR. WALSH: I believe there is an update on a 2011 MPR and I don't have the exact spread on the drop, but I believe it's in the magnitude of $15.00 a megawatt hour, roughly? I'm looking at Jason.

MR. LEWIS: But even that, I think that was still -- gas prices were still fairly high even with that, compared to where they are today. I mean, gas now is in the $2.00 to $3.00 range, so --

MR. WALSH: I'll just build off of some of Mr. Lewis' comments. I might separate competition and pricing, I would say in terms of the response we've gotten recently in our solicitations, they've been very robust. We've had a tremendous response from the market. For prices, I think there's a lot of things that can drive that, that are basically outside of the control of California and us, and even the developers, for example, PTCs for wind, ITCs for solar, are going to be a major driver in pricings coming in the future, so the fact that we're on a downward trend, I think, is far from a guarantee that we're going to continue on one.

MR. TRACY: At SMUD we've, for the last two or three years, been pretty much over-sourced on renewables, so we aren't going out for formal bids, but we do get unsolicited offers and we do see the prices coming in the door cheaper, especially for solar projects. maybe only slightly cheaper for geothermal wind and other type projects.

You know, my background is in economics and I get a little bit cynical about some of this stuff in the market. I mean, when you have a situation where you have a mandate to go out and so the demand is huge, and the suppliers are just cranking up their projects, and you have a referent price out there, I mean, to me it just -- it doesn't really matter what the developers' costs are, they're going to look at what the market price is because it's essentially a seller's market.

And indeed, when we were looking out three years ago, I think the spread in bid prices that we were getting was pretty tight across all the technologies. Now you're seeing a much wider spread in the bid prices, at least the unsolicited stuff that comes in the door, and that's more indicative of a market where there's a little more balance between demand and supply. And so I think that, going forward, you know, as long as we have a measured approach to how we procure and how much we procure, and don't do it in these big lumps, I think that there's a better value for the buyer.

The other thing is that, you know, typically in an unbalanced market like we were seeing two and three years ago, the offer -- the structure of the offer coming in the door was, "Well, this is it," you know, it's a take and pay contract, you have to take everything that we generate, there's no dispatchability, you know, and I think maybe for a utility that wants to push it a little bit, you could go back to a set of bidders and start talking to them about, well, here's some things that would be valuable now in the market to actually regulate the market and give us some flexibility in how we schedule these resources, and try to trade off some price for that type of flexibility that utilities are used to seeing in terms of their standard kind of contracts with natural gas plants and so forth.

COMMISSIONER PETERMAN: Randy?

MR. HOWARD: Yeah, I did want to add a little bit, so thank you. L.A. kind of has taken a little different approach than probably some of the others at the table in trying to benchmark and understand that we are getting the best price and value, and so we do solicit -- we have -- last year we issued through Southern California Public Power Authority, SCPPA, an RFP on the street. We kind of outlined the resources we were looking for, where we were looking for them, and we received over 200 proposals. And then through that process, we short listed, started negotiations, but we also decided to do something a little different, we went ahead and opened up our RFP to be open and continuous, so those that didn't make our first cut, we told them, you know, revise, take another look, revise, you didn't meet our cut, and we didn't always tell them exactly why, but we gave them an opportunity to re-bid, readjust their prices, and we've certainly seen that happen multiple times as people are still trying to get a project in the door. And so that's been very very helpful to allow them to look at their project, go back to their vendors and say, "Look, we didn't make it this time based on the proposals, help us with pricing," and they've done that, and we've been able to reduce costs and, in some cases, up to 20 percent. So quite significant from what the first proposals look like.

The other thing that we've done is we went out and decided to build some of these ourselves, so, 1) we have a little better understanding of the projects, the development cycles, the technologies, and we've just finished our first 10 megawatt solar project and started construction on our second, and then we built our 135 megawatt wind farm, and I think SMUD has done something similar.

So when they come in the door, the project proposals, we look at the weather data that goes with them, as they come and say, "Well, the capacity factor we think it's going to be this," we can validate that pretty quickly, we know the wind zones, we have experienced engineers that, now operators as well, to put a valuation to the proposals. And I think that's been really helpful in us getting some of the better deals in our transmission.

MR. SIMON: You know, I think the only thing I would add is, you know, we see all the numbers for the solicitations and, from the last RPS solicitation we had in 2009 to the 2011 solicitation, pricing on average was down about 30 percent, but you have to remember that most of the projects that were shortlisted in the 2011 solicitation, 75 percent of them were solar PV and 25 percent were wind, so it's highly representative of two technologies. When you look at the spread, the pricing spread, between I think the most aggressively priced technology and the most expensive technology, it's very wide. So what that has resulted in is it resulted in utilities procuring differently and they're procuring probably more on a price-driven basis, and obviously with a consideration of value as we were discussing before, and probably turned away from a lot of the higher priced contracts because, at this point, as we were discussing earlier, a lot of the value associated with these higher price projects cannot be quantified at this point, which is obviously something that we're working on.

COMMISSIONER PETERMAN: Jason, can you touch on or remind me what the attribute categories are for the solicitations? So there's peaking, and I thought there was --

MR. SIMON: You're referring to the FIT proposal? Peaking, baseload and off-peaking?

COMMISSIONER PETERMAN: Peaking, baseload and off-peaking.

MR. SIMON: So in our large solicitations, there are no technology buckets, but for the RAM solicitation, there's an as available non-peaking, as available peaking, and baseload, and the same for the proposed decision in what's called ReMAT, the SB 32 program.

COMMISSIONER PETERMAN: Thank you for clarifying that for me because I was trying to reconcile the 75 percent solar, 25 percent wind, in the last solicitation with my memory that there was some attribute classification, and you're right, it's in the RAM, not in the RPS. Thanks.

MR. VIDAVER: A point of clarification, Jason, you said the spread is getting wider, are you talking about the spread between high price and low price solar, for example? Are you talking about the price spread across wind and solar?

MR. SIMON: I'm talking about the price across various technologies, so solar PV, wind, solar thermal --

MR. VIDAVER: You know, technology is becoming cheaper --

MR. SIMON: -- biomass, geothermal, and small hydro.

MR. VIDAVER: Okay, and you also mention that there is some attributes of higher priced resources that hadn't been quantified or that needed to be --

MR. SIMON: Well, they're difficult to quantify, as Dave was saying. I mean, if you were to take, for example, a solar thermal project that incorporates storage, we don't know what our long term system needs are now, so it's very difficult to figure out what the capacity value is associated with it, and we don't know, for certainty, how that particular project is going to be optimized for the utility's needs, and depending on how you're optimizing that particular facility and depending on your long term system needs, it's going to largely depend -- it's largely going to determine what the capacity value for that particular project is. And, you know, a lot of it has to do with the resource mix. So you know, the more solar PVs you start putting on the grid, the lower the capacity value for solar PV relative to the capacity value associated with maybe solar thermal storage. And that, I mean, that study that I've just basically paraphrased is a study that came up from Berkeley National Labs by a researcher named Andrew Mills, and it's something that people are looking at right now, and this whole issue of, obviously, integration.

MR. VIDAVER: Maybe that's a good segue into the next set of questions, and perhaps we could use solar PV and solar thermal with or without storage as an example. It's my understanding of bid evaluation that the utilities look at the value of the energy provided based on, for an intermittent resource, an 8760 generation profile, and will come up with sort of a market price for energy during each of those hours, and a capacity value for the resource, and for a solar thermal plant, there might be some degree of dispatchability, I'm not an expert on solar thermal technologies, but one would expect that a solar thermal plant would probably have slightly less variability and output. So would you expect -- do these 8760s sort of -- do you use those to ascribe both value to the energy and to capacity value to the resource? A question -- yes?

MR. WALSH: Yeah, the answer would be yes. So we take, for SCE's evaluation, yes, it's against market forecast of energy prices based on a generation profile for each hour of the year. For the capacity, to determine the quantity of the capacity coming from the project, we use the current exceedance methodology at the CPUC for measurement of intermittent resource -- well, the wind and solar resources -- some of the dispatchable resources have their own QC counting methodologies at the Commission, so they reflect that, and then the market price capacity. I would say, in our valuation, the one piece that's been missing has been these integration costs. We've been ordered to make them zero for the last couple number of years, at the credit of the CPUC, it's one of the issues currently before them to start including those costs, but I think that will help better allow us to quantify a difference between, say, a solar PV and a solar thermal facility where a thermal might have more ride-through capability when it gets cloudy, essentially.

MR. VIDAVER: Do solar thermal facilities generally produce 8760s that reflect that ride-through capability? Do they generate at a higher availability factor later in the day?

MR. WALSH: So just the natural shape even between solar thermal technologies can be a little bit different, and even among solar PV, you'll get a different shape for a fixed tilt vs. a single axis tracker. So it's really technology-based. In terms of demonstrating ride-through, you wouldn't necessarily see it in the 8760 because we're taking just a year's worth of data called a typical meteorological year, and doing our calculations. So you're obviously not catching a cloud at 2:00 on August 3rd or something along those lines.

MR. VIDAVER: Or 2:15.

MR. WALSH: Yeah, exactly.

MR. VIDAVER: Okay. Do --

MR. TRACY: SMUD pretty much -- we kind of break it for like solar into like three different categories, one is the market value of it. But we also, because we are sort of a transmission constrained service area, and especially on peak in the summer, you know, our constraint is how much we can actually input because there are limits, so we have a different value for a solar resource that is located within our service territory vs. one that we have to buy and export, so we give it local capacity value. And then, the other thing with solar that we really focus on and, as an example, when we did our 100 megawatt feed-in tariff offering, what we did ahead of that offering is we went through all our distribution circuits and we said, you know, if we were to have up to five megawatts come on to an individual distribution circuit, what would that impact be? Would there be no additional costs necessary to accommodate it? Or are there some circuits out there where it would cause problems, and we would have to have an incremental investment as a utility. And so we attach to the offer, or the solicitation, here are basically the circuits that are open for solicitation, if you want to put it somewhere else, you're going to have to talk to us because you're also going to have to pay for some of the upgrades that are required on that.

The other interesting thing that we've done is a study on the variability of solar, so within our service area, we've done a study where we've got the sensors for the solar intensity across the whole service area, and we model that on a clear day and on a cloudy day, and on a cloudy day, the amount of up and down within the whole system look like, you know, you've jumped on a waterbed, and it was just bouncing all over the place. And so that's a factor that we're very cautious about how we incrementally add solar photovoltaic to our system because we need to understand how it's going to impact the voltage levels on individual circuits, whereas if it was a solar thermal, even if you have a partly cloudy day, you don't have those issues that you have to deal with in terms of the distribution system and maintaining voltage stability.

COMMISSIONER MCALLISTER: A couple of questions here. So I want to ask the investor-owned utilities if they've been approaching kind of this locational issue in a similar way, or in some way, to what SMUD just described. I know Edison, for example -- I think all the utilities at some level have done maps of congestion and things like that to try to aim the renewables investments, but I'm kind of wondering a little bit more if you could talk to that more specifically about how you're enabling developers to pick -- to propose for spots that actually can accommodate the renewables and, you know, some kind of a node, sort of a node incremental positive or negative price, you know, depending on what the impacts are, or something like that, and if each of you could speak a little bit to that and what you're doing?

MR. LEWIS: Sure. From our standpoint, it's important to keep in mind that the transmission side of the house is completely walled off from us on the procurement side of the house through FERC Regulations, so we don't go into details about polling anybody, we let the developer primarily do their own studies to determine what's the most efficient mechanism and where they feel the best place is, given their resource and what they want to do to interconnect to our system. We also have some kind of guiding principles, though, as well, that we try to help -- you know, there's a transmission ranking cost report that's part of the CPUC process that we also provide, as well as I believe in our solar PV solicitation we also kind of provide a map with potential areas that they could look to explore, but there is this kind of walled off issue that our transmission side of the house handles separately, all that interconnection process. So it's slightly different than SMUD.

COMMISSIONER MCALLISTER: Okay. Well, so -- oh, yeah, sorry. Go ahead.

MR. WALSH: Sure. No problem. There is an interconnection map offered by SCE on our website that gives sort of available capacity on certain circuits. Part of the problem is you make that public, that's where everybody goes, and now you're just having a bunch of people competing for the same area. We do measure, as part of our solicitations, the transmission costs associated with, and we only measure the costs that are paid by our customers through the Transmission Access Charge, the network upgrades. All the other costs, the distribution upgrades, those are the ones that are paid directly by the generator. We still -- the customer still winds up paying for it, it just winds up in the energy price that they bid to us, so it's all accounted for, it's just a matter of where we're taking care of it.

From a congestion standpoint, that's a whole other question. Our philosophy has been you look towards -- is the generating facility contributing towards localized congestion in an area, in a sense, are they interconnecting as a fully deliverable project? Or is the amount of transmission being built out where they can actually be delivered to load? If they are, then there's no congestion adder associated with the project; if they are interconnecting energy only, we do add a congestion adder.

COMMISSIONER MCALLISTER: Then, so thank you, so I guess maybe it's a little bit -- SMUD, if you can give a little bit -- Jim -- you could talk a little bit more about SMUD's process and why it's sort of easier. I know you're an integrated house in many ways, but why are you a little more flexible on the communication to potential developers on siting -- or, if you are, maybe you're not.

MR. TRACY: Well, I think that, first of all, we work very closely with our Board. The Board puts together pretty clear policy directives for the staff, and so in trying to enact that, we try to work with the community, we try to work with, in this case, the Board wanted the feed-in tariff, they wanted it to be successful. And one thing that we saw was we get a lot of bids, and we're talking about not the congestion, but really down to the 12 kV circuits, the distribution circuits. And you know, the developer is doing all of that work and putting a proposal together, then we tell them, "Oh, by the way, we just added 20 percent to the cost of your project because we've got facilities that we have to put in here," that we thought it was just better in this particular instance to facilitate it through putting that out on the table and saying, you know, "You guys, just be aware that these are the circuits that work and these are the circuits that don't work." So I think, more than anything, it's probably just, you know, the size of the utility, it allows us to be a lot more collaborative within the utility, but I think it's also just the approach that SMUD has in dealing with the community and with suppliers like that.

COMMISSIONER MCALLISTER: Okay. Thanks. One other question. So how helpful would it be -- so we talked a little bit about differences between technologies and solar thermal having better ride-through, and sort of the time range issues that impact your planning or make it more difficult, so the Commission has been funding and other work is going on to enable more predictive capacity on solar resource in the very near term, sort of hours ahead, even less ahead kind of thing, how much value do you see that having in your planning and your ability to maintain reliability while incorporating more renewables? Like sort of what role does that very near term predictive capability -- could that have -- say, for PV?

MR. LEWIS: Are you talking specifically about adding storage such that you can --

COMMISSIONER MCALLISTER: No, I'm just talking about, okay, there's a cloud coming off the coast that's going to -- forecasting, near term, yeah, forecasting the PV output based on immediate weather.

MR. LEWIS: Obviously, that would be extremely helpful, you know, to manage some of this intermittency. I think the big question that we have is exactly what level of intermittency are we going to see, so we're kind of predicting for what the future may be. We have a tremendous amount of resources that are coming on line over the next couple of years, and there's just a lot of hypothesis as to what that may represent. Some of our preliminary analysis shows that some of the intermittency might be as much or greater than $7.50 a megawatt hour, as we've talked about in this morning's presentation, but it's difficult to really quantify what that is, so we need to, I think, look at a point where we've got to see how this system actually develops over the next couple of years, and the next couple of years are going to be absolutely critical to where some of these costs may or may not appear, and then what are the most efficient ways for managing some of those costs and managing some of those issues.

MR. WALSH: Too much said, it certainly would be helpful, our Operations Group has a fair amount of weather forecasters, I don't know if they get down to the cloud level, but our Operations Group is pretty heavily involved in that. But again, I think just in general it's an important component that needs to be considered when making our procurement selections going forward in terms of what the integration impact will be on a solar PV, or wind heavy type portfolio.

COMMISSIONER PETERMAN: Thanks. And I'm going to tee up a question for later and then return back to David for his list of questions, but you just started to touch on this. I was thinking about what are the policies that the utilities -- in particular, but also the State -- can pursue to reduce costs, and one just being mentioned is -- or what activities can one engage in that you can effect and one that would be forecasting, for example, to be able to have a better prediction about intermittency and reduce those costs. And Randy touched on one, just their policy of at least with one of their solicitations having an open and continuous process and then allowing that as an opportunity for bidders to come back with lower costs. So I would ask you all to think about particular policies that you're currently engaged in to reduce renewable costs, as well as potential future ones. But, David, back to you and your questions.

MR. VIDAVER: Thank you. You've alluded to the fact that integration costs enter into your evaluation because of CPUC decision, and that the CPUC -- Mr. Simon said that the CPUC is looking at this. Can you just quickly summarize what those integration costs are, not numerically, but just what are the integration costs that you incur, that you don't value, or are not allowed to value? One could think of incremental ancillary service needs and when you say you would like to incorporate integration costs into your bid evaluation, exactly what are you referring to?

MR. LEWIS: Well, I think that's really the big question is exactly, what *are* those costs? And right now we're at a phase of, you know, at PG&E we're at about 19 percent with our current RPS target, you know, going toward 33 percent. And over the next couple years is when -- I think I added it up the other day -- we have something like 1,900 megawatts of solar PV coming on line and 1,800 megawatts of wind coming on line, so we're going to find out what exactly those costs are, you know, whether we like it or not, and that's one of the key things is, right now, it's just speculative. There is certainly, you know, if you look at any kind of solar PV profile, you know, one cloud moves over and it moves up and down like a needle, and that has a cost on the system. I don't think there would be anyone that would dispute that. But it's one thing to recognize a cost, it's another thing to quantify it and prove, then, that you can manage that cost more effectively. So that's the big question that we really need to solve as our portfolio changes and moves towards the 33 percent.

MR. VIDAVER: Can I ask a clarifying question, too? So, if intermittency -- as the cloud moves over, the costs you're referring to is need for regulation, I would assume?

MR. LEWIS: I’m not the operations guy, so you're probably asking the wrong guy, but you know, I know when we're talking to our operations people, and I present them with the next renewable contracts that my team is responsible for signing up for, they're very concerned about what's going to happen, how this next piece is going to add to the volatility that they're expecting, if it's solar PV, and even to some degree wind. Now, similar to a lot of other people, we're trying to work with other counterparts to better understand what are the capabilities of some of their systems. And there's been a lot of advances, and I know in kind of the wind side, where you can change around some of the turbines, and you can modify it and you could to some degree manage their dispatchability, if you will, but I think we're still a long way away from making that happen. And, still, as I started with our opening comments, our contracts still are based on a dollar per megawatt basis, so the developer only gets paid as they're producing, so there's kind of disconnect in between how maybe the market is structured and at least some of these contracts are structured, and actually from an operations standpoint, too, which you may or may not need to achieve.

MR. WALSH: I think the big driver in those are the ancillary services necessary in order to integrate these resources, especially if you're going out and these are 20-year agreements, and as the portfolio grows, there's more intermittent resources, the question is, do we have enough flexibility capacity on the grid in order to serve all these additional intermittent resources?

MR. HOWARD: This is Randy, if I could -- could I add a little bit to this?

COMMISSIONER PETERMAN: Yeah, Randy, you should jump in when you want to because it would be hard to acknowledge you, always.

MR. HOWARD: Yeah. So I think I brought up some issues the other day in one of the other IEPR workshops, is we have been looking closely at some of the PV systems, you know, just the puffy cloud cover that causes them to go from 50 megawatts to 10 megawatts in a manner of less than a minute, and so as we're looking as a utility to ensure that we have the capability of integrating that, and similar to PG&E, you know, we've never operated at these levels of renewables in our history, so there's a big learning curve for all of us, and our operators continue to get nervous every time we add another project. But they look at this going from, say, a 50 megawatt to a 10 megawatt of a single site, and that has a particular risk profile that we try to incorporate. So when we talk some of these larger PV solar projects, maybe 200-250 megawatts, our operations folks get quite concerned because they believe our cost of integration on that large-scale is a little greater than it would be if we did a whole bunch of, you know, 10 megawatt projects distributed around various areas. So we do look to minimize the cost to our ratepayers, being in different solar basins to try to ensure that we're not stuck on one day with a lot of different intermittency for the bulk of our system. And we also, as we look at, say, putting in peakers, we've determined that our peakers really won't accommodate the intermittency of solar PV, it's going to help us with the integration of our wind, but not really with our PV, they're just not going to be fast enough, and we're going to have to rely on spin or some of our hydro assets, and so we're trying to factor in what would be the cost. So the solar PV systems, by far, for us, in our studies to date seem to indicate that they are going to be our highest cost integration. The obvious benefit, though, of the PV is they're typically generating when we can use that energy the most.

MR. TRACY: This is Jim Tracy and I would agree with Randy that the solar is a big challenge and, as an example, within our service area, if we have X amount of solar that is expected to be on through the peak, we probably have to reserve some of our hydro that we otherwise would have been running on peak at the most optimum time in terms of releasing that water. To the extent we didn't have to use the hydro to fill in, we have water that's been moved from on peak to a less desirable time period. And so that's just one of the ancillary service-type costs and how it manifests itself.

Just a comment that I would have is, beyond ancillary services, the cost of transmission for all the renewables in the state -- and I think SMUD has been pretty clear that getting really clear policy direction, what are the policy goals of the State, as opposed to specific mandates on how we get there, just like any market, if you begin to constrain the ways that you can reach a policy goal, then you're going to have a less optimal solution, it's going to be a more expensive solution. So if we're building transmission so that we can bring power in in Southern California, as opposed to using unloaded intertie capacity, bringing it in from out of state, obviously that's going to increase the cost. And so you have to say, "What's the policy decision on that? Is it for jobs?" And if it's for jobs, then somebody really needs to do the study on how much is the transmission and all of the renewables being built in the state adding to the cost of the renewable bill here in California, and what does that do to all the other industries outside of the green industry? And look at, on a net basis, what's happening to jobs. Because I think that, really, if the State could get more focused on what are the policy priorities, then we could have a better way of assessing what's the best approach to doing this, as opposed to just trying to optimize a sub-optimal portfolio.

COMMISSIONER PETERMAN: This is Commissioner Peterman. And, Jim, you probably heard me say this before, but regarding the policy goals, just in the most recent RPS legislation, there are nine pieces of intent language there with different goals, including -- and not one of them, actually, is explicitly jobs -- but displacement of fossil fuel, local air pollution, climate -- you know, and greenhouse gasses -- and so I think we'll come to a point where there's not -- it's going to be hard to prioritize among some priorities, but your point is well taken.

I just want to make an observation, and then we'll continue further discussion, that we've heard both in the panel earlier this morning and today that we've just seen that there has been a switch to solar PV because some solar thermal, we've seen more investment in solar PV because the technology costs are coming down. But then we've heard from the panelists today that the integration costs for solar PV may be the highest, or may be the most uncertain, but those are not yet being considered. And so it does bring to mind a general concern that, when we look at all-in costs, how do the technologies compare across each other? And are we investing in the technology primarily that will result in greater costs in the future. It's more a statement than anything, but if you have anything to say on that, feel free.

MR. WALSH: I think the recent decision at the CPUC -- or, excuse me, the recent ruling -- was a step in the right direction to figure out what the true costs and benefits for all these technologies are.

COMMISSIONER PETERMAN: And, Jason, just a quick question, can you speak to the timing on starting to consider these integration costs, and to what extent they might be eventually considered in the solicitation criteria?

MR. SIMONS: Well, sure. There's a number of things happening. On our end, we -- I think it's published in the Commissioner's Ruling three months ago for, I guess, the initialization of the 2012 RPS Procurement Plan. Within there, there were a number of staff proposals, one of which was the need to basically standardize the NEM market value calculation, or as Southern California Edison calls, Renewable Premium Calculation, it's basically the value of the project, so that's the first thing we're doing. The second thing we're trying to do is we're trying to incorporate all these costs that we think are going to be important where we're looking out 20 years, such as integration costs, obviously the value of ancillary services for that perspective. So that's the first thing we're doing. The second thing that's happening is more in the LTTP track, and there continuing to study what the integration needs are for the State, and they're coordinating with the IOUs and California ISO. And I understand that there may be a decision out next year with respect to what the integration needs for the state are. As of now, as Bill was saying, the Commission has ruled through a recent decision that there is no need for integration.

MR. VIDAVER: I don't want people to hear me breathing while everyone else is talking, so I shut this off. You mentioned that the capacity value of resources is going to depend on the whole portfolio of resources that we have at our disposal. And I assume that the capacity value of resources within a utility portfolio is going to depend on what's in that portfolio. I took the liberty of looking at load chips for the PG&E and Edison TAC areas on high load days in 2009, 2010 and 2011, and one thing struck me, that the difference in load from the peak to 6:00 in PG&E, it was only about 300 megawatts on high load days. And it was only about 800 megawatts to 7:00, by which time you're getting very little solar. So is there -- does the CPUC and the utilities believe that the look at resources going into a utility portfolio, with an unchanging capacity value for some of these resources, can continue at very very high levels of intermittent integration? Certainly, you're going to look at that in LTTP, I'm just wondering if either of Edison or PG&E have looked at that in the context of their own portfolios. PG&E has about a 300 megawatt drop. Edison, on the other hand, generally experiences a very severe load drop in the two hours after peak. But in PG&E's case, it's less than that. Has PG&E looked at the -- you said you have 1,900 megawatts of photovoltaics in your portfolio already, and I imagine there's more coming down the pike.

MR. LEWIS: We have 1,900 that's kind of going to be coming on line over the next couple years, and that's one of the things we're looking at is, how is our load peaks going to shift as this solar PV comes on line? And that's one of the things that we need to better understand -- what is the total impact going to be to our system? It's going to be that, you know, our traditional load has kind of peaked in the 4:00 to 6:00 p.m. timeframe, and it's going to be interesting, is that portion, as solar PV starts to decrease in its output, what impact does that then have? And then, also, in the morning hours, as well, we're concerned about what's going to happen in the morning hours as the solar PV comes on line, with the sun coming up, but necessarily our load might not have caught up to it, too. So we're looking at and running scenarios as to what that may mean for our system, but it's got to be coupled, then, I think with what's going to be the real world experience, too, not just in the analysis side.

MR. TRACY: Well, I was just going to say that, you know, at SMUD, what we're looking at is not just the supply side resources and how that's going to deal with the peak and solar energy. In our service area, the peak happens around 6:00, obviously it's a problem with solar maybe at 25 percent of output at 6:00 in the summer, but when you combine the solar with the load, what you end up having is a much narrower peak, in effect. And so when you begin looking at that, there are some opportunities, then, around load management and demand management. It's very challenging to work with your customers when they have to manage load across a five or six-hour peak, in order to get the load reduction. But if you've got a lot of solar and it's basically pushing your peak into a much narrower range, then you've got a lot more options open to you in terms of working with your customers to manage their load for an hour or two hours.

And so that's one of the things that we're going to be studying and looking at, and potentially designing the management programs around if the system evolves in that direction.

COMMISSIONER PETERMAN: A quick -- I'm sorry, if you were going to respond? A question?

COMMISSIONER MCALLISTER: I really like where you're going with that because I feel like this integration at both the customer level and potentially at the circuit level, or whatever appropriate level in the utility is kind of a key -- it's an interesting idea that needs a lot more thought going forward, and particularly, say, at the customer level if you have -- I mean, we've mostly been implicitly talking about, you know, largish-scale renewables here and the RAM procurements and etc., but you could scale this idea talking about mixing demand management, you know, whether it's demand response or whether it's sort of aggressive energy efficiency, or customer-based DR, or whatever, with distributed renewables or just renewables, generally. So I like -- I feel like that doesn't happen in the marketplace as much as it could. I'm wondering if any of you work with your customers really to offer at the more distributed level that kind of an integrated solution and, meaning, if they want to put on some kind of self-generation, whether it's solar, or whatever, that could be complemented very well with some kind of demand response such that, since solar generally is not considered to be a firm resource, you've got a couple days of it month-to-month, in the middle of summer, where you're going to have less capacity than the design capacity of that system, could you chime in at that point with a control event, you know, Demand Response, or some other kind of resource that would allow the customer not to be regularly impacted, but would also harvest the self-generation that you put in and enable you to manage your grid at the same time. I guess, so I'm pulling the discussion slightly down to the distributed level and asking more about the integration of programs at the customer level for the utilities. And if the PUC has anything to say about that, that would be welcome, too, sort of the program integration. I think it's a powerful idea that we're just kind of getting started thinking about at the programmatic level.

MR. SIMON: Well, I think if I'm following it correctly -- and this kind of dovetails into the Cost Containment Initiative that Brendan could talk about, something that we're going to be implementing probably sometime next year, so we recognized at the Commission, at the CPUC, that Cost Containment for 30 percent legislation is a foregone conclusion. You know, as Dave was saying, most of the utilities at this point have procured largely resources for 33 percent, but that doesn't necessarily mean that all of them are going to come on line, there's obviously risk associated with project failure. Nonetheless, because we are going to be implementing legislation next year, we do keep in mind that, you know, the broader perspective at the CPUC is to look at things from a resource planning perspective, so we want to make sure that the Cost Containment initiative that we are going to be implementing is going to complement the longer term resource planning initiative for the State, and from that perspective we are going to be looking at loading order, and we are going to be looking at where renewables fits in at that particular loading order, essentially -- which gets to your perspective of, you know, looking at energy efficiency vs. demand response options vs. renewable energy and seeing how they could work with one another, seeing how they could be integrated, and seeing what the net economic benefit are of obviously various portfolios.

COMMISSIONER PETERMAN: Since we have about a little over 15 minutes left for this panel, I wanted to ask a question, as well as suggest to the Moderator that we open it up to a couple audience questions. You touched a bit, Jason, on the issue of project failure and uncertainty, and I was just wondering if anyone would offer a perspective about what costs are incurred because of lower project certainty and kind of thinking again about what are things we can do at the State level that can provide some more certainty, whether it's through the planning process, or something like that, or whether there is a real measureable cost associated with them.

MR. LEWIS: Well, one of the things that we see and it's kind of interesting about the kind of open-ended procurement that some of our colleagues have, I think was LADWP was saying that they were kind of leaving things open. We're trying to shorten and contain our things. We've been very consistent over doing a number of different solicitations, and anything that we can do to shorten the length it takes not only just to close a solicitation, but also on the approval process, you know, adds to greater certainty that the projects are going to be able to go forward and then adds to them to be able to price something that reflects the current market at that time, as opposed to having it take a number of months, if not up to a year, even, to get something approved, and what can change in the market during that time that can blow up what was a solid deal. So those are some of the things I think are, you know, the low hanging fruit in which to improve the process.

MR. WALSH: I would parrot that. One of the -- I think the easiest way to bring more certainty in terms of the cost and the success rates on projects is contract approval; I think we're starting to see a market response where there's a little more nervousness on attaining CPUC approval with respect to contracts.

MR. TRACY: I think certainly at SMUD, one of the criteria that we used to determine which projects we selected as the probability in our estimation of whether the project was even going to go forward, so we might have paid a little bit higher price for one of the projects we selected, but it was a project that was already permitted and they had financing and were ready to go vs. one that was a concept that was quite a bit cheaper. You know, we've been through that mill before, so it was a big consideration in our screening for ultimately the projects that we chose.

COMMISSIONER PETERMAN: I know, Randy, if you have a comment -- but I also wanted to ask Brendan, since you have not been as much the focus since you are not a utility, I wondered if you had a comment or question for any of the utilities.

MR. PIERPONT: Well, I just wanted to maybe highlight a few of the kind of thoughts and takeaways from looking at other states' experiences that we were thinking about, that might be useful in the California context, and I would love to get kind of your perspectives on this, as well.

So the first is, I mentioned a little bit before kind of the cost limitation exercise is not necessarily going to get you cost-effective policy, and so maybe some suggestions from your point of view on which policies are actually driving more cost-effective procurement when you're thinking about these, given that California does have a pretty broad suite of procurement policies in place.

The next is that the cost limits should probably be set in a way that's consistent with expected costs of the RPS, and a lot of other states tend to pick kind of politically palatable cost limits, so I would say a one or two percent rate impact over X number of years, where that might be inconsistent with even an estimate of costs to achieve an RPS. And so just some thoughts about kind of, I guess, which risks California ratepayers should be bearing, and which ones are appropriately managed by the IOUs, and which ones should California ratepayers just not be exposed to at all. I'm thinking here about things like Federal policy, or technology costs.

And then some ideas on a lot of cost limits in other states have been pretty poorly defined in how they're calculated and what assumptions go into the calculations, so maybe this might be an opportunity to talk about kind of the value of, I guess, a flexible calculation vs. something that is hard and set may be useful there. But, overall, I guess.

MR. LEWIS: Well, I think on maybe kind of the overall Cost Containment aspects of it --

COMMISSIONER PETERMAN: Your colleague is up there, by the way.

MR. LEWIS: Good, I'll let her take that.

MS. WINN: Valerie Winn from PG&E. I did tell Dave that he's our procurement expert, but I would save him from the Cost Containment mechanism questions.

COMMISSIONER PETERMAN: And we are going to delve into that more so in the rate panel, but please.

MS. WINN: Uh huh, no, and I think as Jason and

Brendon have noted, a lot of the work on developing that Cost Containment proposal, we're just getting started. Certainly, the mechanism that was in place under the earlier 20 percent program, you know, utilities could procure up to -- I think we may have had -- it was less than a $1 million that utilities were supposed to spend collectively above the market price referent, and of course, I think we blew through that with only four or five contracts, but then continued to voluntarily procure.

So under the 33 percent mechanism, what we're looking at, and there's still a lot of work to be done here, but certainly at the outset, having a cap that gets updated constantly is not workable, you never know what target you're working towards. So we would like a cap that is set at one point in time, and that becomes our budget for the program, and it remains fixed, and we work towards, you know, filling in that cap so that our customers know what to expect from a rate impact perspective. You know, it needs to be clear as to what counts towards the cap -- is it integration costs, as well as the generation costs, as well as incremental transmission and distribution upgrade cost? You know, and it needs to be a meaningful -- a clear, stable and meaningful cap. And it also needs to be easy to administer. You know, sometimes we make things a lot more complicated than they need to be, and I have to say the MPR and the supplemental energy payments and all of that, it was interesting, but it was rather complicated and difficult for those who aren't steeped in energy policy to understand. So those really are clear -- are overarching principles, clear, stable and meaningful, easy to administer, and that it's fixed at the beginning of the program and, once it's done, we have other alternatives that we look at.

MR. TRACY: I'll just mention quickly, you know, with SMUD I think in terms of cost -- and we're not involved in the Cost Containment proceeding or issue, but I think the thing that we are concerned about the most is what resources we build that are going to support the renewables, that's going to over the long run be a very very big component of the overall cost of doing the program. And when we're looking at -- I mean, we're actually looking at a hydro pump storage facility, we're looking at a compressed air storage in an old gas field, we're looking at gas turbines, but when we look at all of those, one of the things that we try to keep in mind is that, if we've got an energy market that is changing as fast as it is, what do those technologies look like in terms of economics in 20 years, or 15 years? Because the concern we have is you build a pump hydro storage and you base it on some ancillary service value, and then in 10 or 15 years, electric transportation somehow is providing some of that ancillary service, and the value of that service has gone down in the market, and now you've got an asset that you still have to pay for, but it isn't needed in the same way as it was when it was first built or you thought.

So it's a difficult -- very difficult decision making process, but I would say that, between the ancillary services and the transmission that is planned in the state, and how that transmission -- because it's spread out in one charge, and the developers don't necessarily see the cost of transporting the energy from some remote site to the system, you get false signals. And those are going to be two of the very biggest costs that the consumer is going to see, as opposed to just necessarily the renewable projects themselves.

COMMISSIONER PETERMAN: Randy, anything on the line?

MR. HOWARD: Yeah, I guess a couple things related to cost and integration. I think -- and PG&E pointed it out, as well, and I've made that statement, the next couple of years are going to be fairly critical to all of us as we add kind of that next big batch. I think getting to 20 percent, we were able to utilize a lot of the infrastructure that was built by our predecessors and ratepayers have paid for a lot of that already. I think this next big grouping of projects to meet the next goal will come where systems aren't going to be so optimal, and I think as we do more of the transformation and transition, there is an expectation that we're going to have greater inefficiencies in our operations in order to be reliable. And so it's probably beyond 2015, 2016, until we can probably tune up our systems -- and I think that's where the greatest opportunity is going to be in some of the CEC activity and in some of our technology improvements. I think the grant funds that you put out there, as people come up with better ways of predicting the wind and the solar indices, and then how we fine tune the systems with storage, or other types of technologies is going to be very critical. But I would assume -- and we're trying to let our governing bodies know that we're probably going to increase our inefficiency in the next few years just to ensure that we can keep the lights on, but it's going to be costly to our ratepayers. They're going to see a higher cost than they would have to if maybe we weren't moving so quickly in some of these new projects, but it's just going to be the cost of doing it.

COMMISSIONER PETERMAN: Thank you, Randy. I think we have time for one or two audience questions if there is anyone who has one. If so, come to the microphone.

MS. BROWN: Hi, there. My name is Elise Brown. I'm with U.C. Davis Energy Institute, the California Geothermal Collaborative. And there are a couple questions out there that I still am wondering what the answers might be. It seems like the conversation today has focused a lot on PV and the intermittency, and wind and the intermittency, and I'm wondering for the IOUs, when you issue an RFP, an RFO, the proposals that you get, do you get many geothermal? And if so, how do you evaluate those?

MR. WALSH: In our large solicitation, we've received a number of geothermal bids. How do we evaluate it? We basically follow the same formula for all technologies. We're technology agnostic, I would say, in our selection, it's the value proposition, and hopefully we're measuring all the costs and benefits from a project. So they're going through the same evaluation process -- you know, I keep sort of harping on it -- but the one piece that's missing is the integration costs that would put a geothermal, with all things being equal, and a better competitive advantage vis a vis a solar PV, but it looks like that's something we're going to change. I will say this, though, a lot of this discussion -- I sort of haven't touched on it yet -- the value discussion, measurement integration, all these costs, the place we're getting it the most is in the large solicitation; the valuation process in the other solicitations is very different and don't necessarily include all of these, and some don't need a valuation at all. So we make sure there are a number of other procurements where a lot of these things aren't being considered, where a lot of discussion has been focusing around the annual large solicitations, but there are many other procurement programs.

COMMISSIONER PETERMAN: That's a good point. Thank you for that.

MR. TRACY: I could just say real quickly, because SMUD is a smaller utility, when we look at a geothermal base loaded plant, and it's a fixed price per kilowatt hour, we look at how it fits against our retail load and, for SMUD, many of the geothermal projects beyond what we already have procured would be surplus in the low load hours, and for us that would mean that portion of the renewable contract would act like a merchant plant. And it produces a lot more risk because you're pushing some resource out into the market at that time, you're paying a fixed price, you're taking a variable market price, and it adds a certain amount of financial risk to take on a project like geothermal against our load shape.

COMMISSIONER PETERMAN: Great. Well, I know we have people with other interests and questions, but I said one or two, and we hit 2:15, so I'm going to keep it at one, but there will be a public comment period right after the next panel. And so thank you very much to all the panelists. We didn't explicitly get to the question I set for the future, which was what type of policies are utilities currently pursuing, the heat cost load, but if you can comment on ones you may not have mentioned in your comments after the fact, greatly appreciated. Thank you very much, David, for your moderation and your organization of this panel.

MS. GREEN: Commissioner, before I introduce our next speaker, I'd like to ask if it's okay to request our third panelists to come up and sit at the table now when we're down.

COMMISSIONER PETERMAN: Yeah, it's perfectly okay. And everyone else might as well stand up and stretch for a second as we get set up.

(Off the record at 2:12 p.m.)

(Back on the record at 2:16 p.m.)

COMMISSIONER PETERMAN: We're entering now into our third panel, we had a good discussion about costs, and how they're not necessarily the same as prices, and we know that neither of them are the same as rates, and so looking forward to better understanding how these costs might be reflected in rates, and whether there are policies that the State can pursue that will ease the transition. Thanks.

DR. BORENSTEIN: Okay, thank you very much. So I'm going to say a few words about electricity rates and a system with high renewables penetration. Basically, these are more general comments about rate design targeted at how do you recover increasing costs due to greater renewables penetration.

Of course, there is the approach of a basic flat volumetric charge that would equate to average cost in order to recover those costs. The problem that we see there, one is that it likely sets price above marginal costs in many periods. Also, that approach is going to exclude un-priced pollution externalities which are generally going to be the case; most of the U.S. uses this approach, that is, in most of the U.S., utilities recover their costs through volumetric charge. Utilities aren't generally very happy about this because that charge doesn't correlate very well with their costs. A large share of their costs are fixed, and therefore they are inclined to include a fixed charge which is used widely in the U.S., but not very much in California. That more accurately reflects the nature of fixed costs, including the transmission distribution fixed costs, billing, and so forth. It has the potential problem that if there are actually un-priced externalities, you could get prices below the full social marginal costs, including those externalities, and then there's always a concern about low-income customers who are often associated with low consumption customers, which I'm going to come back to in just a minute. And of course, a fixed monthly charge on the residential side tends to hurt people who are low consumption customers.

In California, we have Increasing-Block pricing, which I'm going to spend a few minutes on, and then there's a widespread discussion of greater use of Time-Varying pricing. Let me start by talking about Increasing-Block pricing, this is just to remind everybody what it sort of looks like, this is actually Southern California Edison's tariff a few years ago. But we still have these sorts of tariffs where the high blocks are price three times as high, for instance, as the lowest block. One question is does this really send the right electricity price signals? And then another concern is how does this affect low-income customers. Let me about the efficiency impacts, that is, sending the right price signals, ideally we would want a price to reflect the full cost, marginal cost, that consumption imposes on the system at every point in time. Increasing-Block pricing really bears no resemblance to that. There's really little or no evidence -- and I'll come back to the very little evidence -- that people who consume more actually -- households who consume more actually impose higher costs per kilowatt hour on the system. To the extent there's a slight difference in the average timing, it might justify a one or two-cent increase block as you get from low to high consumption, but nothing like what we have now. So Increasing-Block pricing really doesn't bear any relationship to the incremental cost.

One motivation has been to encourage conservation, which I'll speak to in just a second. Another one, which I'll come back to in a moment, is that Increasing-Block pricing protects low-income customers from rate increases, and this was clearly the motivation during the California electricity crisis with AB1X where they allowed higher tier prices to go up, while freezing lower tier prices. And if you look back at the legislative history, certainly the discussion was about protecting low-income customers.

On the efficiency side, this idea of motivating energy conservation, the idea is that with very high incremental prices, it'll get people to cut back. That concept could make sense potentially if people really focused on those marginal prices, but of course, if you asked the average person on the street where they are in the Increasing-Block schedule, they will have no idea what you're talking about; most consumers don't even know we have Increasing-Block pricing. My former graduate student, Koichiro Ito, who is now a post-Doc at Stanford, wrote a really excellent paper looking at this empirically, and concluded that, by comparing customer behavior over rate changes in adjoining utilities, that customers really aren't responding to marginal prices. They're much more responding to average prices, or total bill. This has some pretty important implications for the conservation effect, in fact, he does some simulations from his econometric results and finds that, given the response he finds the effect of Increasing-Block pricing on conservation is probably about zero. And there's an intuitive interpretation in that, of course, if customers are responding to average prices, about half of all kilowatts have to be sold at below the average price, and about half have to be sold at above the average price. And so, as you spread those prices, if that's what they're responding to, then net effect is likely to be about zero, and that's what he finds.

You might be able to train customers out of this with greater education. Koichiro and I are working on a paper right now to look at Southern California Edison's bill redesign in 2009 where they put a thermometer on the bill that fills up as you consume more, and unfortunately, while I think that's a valiant attempt to inform consumers, it doesn't seem to have had much effect. We're finding it might have had some effect on customers in the Central Valley and certain very hot areas, but overall the average effect seems to have been extremely small. I think it's actually very difficult to get people to focus on this. I probably would have designed the bill slightly differently, but I haven't focus grouped my design, so who knows whether it would have been more effective.

Then you have to ask the question, even if that does yield conversation, is that the conservation you want? Do you really want people conserving to avoid $0.30 power while other people are consuming at $0.10 power? And the economics of that are pretty straightforward, there's no reason to think that somebody doing something to avoid $0.30 power is what you want when other people are, even if they were rationally responding to marginal price, are responding to a ten-cent price.

So if you really did want greater conservation, there's a pretty strong argument that what you would want is to raise the marginal price for everyone, not to have a wide spread of marginal prices.

Now, the second concern about our argument for Increasing-Block pricing was that it was there to help poor people. I've done some work on this, and actually show that it does, that poor people on average do consume less than wealthy people. Although the protection is actually smaller than one might think, the average effect I found on people in the lowest quintile of household income comes out to about $5.00 a month. It would actually be about twice that if there were no CARE program, but because the CARE program is protecting a lot of customers already, the incremental effect of also having Increasing-Block pricing is reduced. One could also argue that if what you want to do is target low-income customers, the CARE program is potentially more effective, but as you dig into the CARE program, you realize there are some pretty serious monitoring problems and usage problems there, as well.

But the bottom line that one has to recognize is that, if what you're asking is, you know, is this a historic way to help poor people, it's really not. There are a lot of poor people that are on high tiers and a lot of wealthy people that are on low tiers, and so it's not terribly well targeted, but on average it does help poor people, the average poor household.

Another rate design that is often raised in conjunction with discussing renewables is Time-Varying pricing, and it's come up in the last session, the idea that by varying prices, we might be able to shape load to fit supply, turning on its head essentially the way the system has been run for years. I did some work back in 2005 trying to do some straightforward simulations asking, in a pure fossil system, how much are you likely to save, and what I found is, for using some pretty small demand elasticity, assuming people aren't going to be terribly responsive, that you could save potentially three to five percent of the energy component of the bill. That seems like a small number, but actually that's hundreds of millions of dollars in California, and I think that's a short run demand elasticity that actually assumes fairly little response. The reason that it's so small is that basically peaker -- the capital cost of peaker plants is pretty low, and so if you really are willing to spend the money to have a bunch of peaker plants lying around, though it does raise cost, it doesn’t raise them as much as you might think.

The potential savings in the long run, I think, are larger, and there are a number of reasons for this. One is that there is going to be supply variability due to the intermittent resources, so this load following supply is going to take on increasing value. Automated demand response is going to increase elasticity, which is going to make this more effective.

Cost-effective electricity storage would actually have the opposite effect, in fact, in the extreme, if we had very cost-effective electricity storage, there's not much value to time-bearing pricing at all because you can always store the power. And as we increase integration of electric vehicles, that's going to change the value. But absent major leaps in energy storage technology, the value of Time-Varying pricing is very likely to increase over time.

There is a concern with Time-Varying pricing that, again, this is going to hurt poor people. I recently released a study that used both PG&E and Southern California Edison load research data actually estimate who the winners and losers are, and one of the ways I broke this out was between poor and rich households, and what I found was that poor households on average aren't any different than other households in their Time-Varying pattern of consumption. That's actually true overall in both of the territories. It's a little -- it's not quite true when you break it out by region, it turns out that, within each region, poor households have slightly flatter load profiles, but more poor households live in the hot regions, those about balance out, but within each region you do see that poor households might get on average about a one percent savings moving to Time-Varying pricing. But it's not going to have much effect.

There would be an impact on large households or large consumption households vs. small, with large consumption households seeing their bill go up a bit, and small consumption households seeing their bills go down five or six percent. And Critical Peak Pricing would also obviously help households in cooler areas relative to households in hotter areas, the inland areas that would actually be fairly easy to offset, as we do right now with baselines, we could also offset it by simply having slightly different pricing in different regions.

Let me finish up by talking about something more directly on point to today's discussion, and that is Net Metering and Increasing-Block pricing effect on distributed generation.

Before I do this, I want to raise an issue that we're talking about subsidies to distributed generation, and it often comes up, and it did earlier today, that there are also subsidies for fossil fuels, and in a recent paper I've written, I've also addressed this; it is true, there are billions of dollars of subsidies to fossil fuels. It is not true that that actually affects the relative cost of fossil fuels vs. renewables much at all. The numbers are in the billions, but the kilowatt hours are in the trillions, and when you actually divided it out, it amounts to less than one-tenth of one cent per kilowatt hour subsidy to -- even if you throw all the gas and coal subsidies into electricity generation. So when you're talking about the relative cost of renewables and fossil fuels, the subsidies to fossil fuels really aren't a significant component, they aren't going to close any significant piece of the cost difference.

So the basic problem when we talk about the Net Metering is that the way these rates have been set, as I talked about, is that we're recovering fixed costs through volumetric charges and, in fact, we're doing it in an exacerbated way by recovering fixed cost through Increasing-Block pricing. So, in some cases, we have volumetric charges that are way way out of line with the actual marginal cost of production and procurement and, even if you add on something like $100 a ton, or $200 a ton for greenhouse gasses, which are numbers well beyond what any policy is considering, the marginal price of $0.30 a kilowatt hour really can't be justified.

So once you start mispricing power in that way, it takes on -- it really exacerbates the issue of Net Metering, and I think the problem we've run into is the discussion of Net Metering is one that's actually -- the underlying problem is mispricing, the incorrect marginal pricing of electricity. And to address that, think about what the Net Metering debate would be like if we actually thought, forget about -- well, let's include the environmental externalities -- but let's say that we had a flat tariff of $0.16 a kilowatt hour, I think the Net Metering debate would just be a much smaller debate because the implicit subsidy from selling power -- from avoiding retail charges by selling power -- would be much smaller.

What Net Metering does, as in contrast to simply reducing consumption, this high price, prices well above marginal cost, subsidize any reduction in consumption, including just turning off a light bulb because you're avoiding a charge that's much higher than the true cost you're imposing on the system. But Net Metering expands that subsidy by saying, if you contribute power now, you can actually use it to offset consumption at another time. And so we're taking a subsidy that already exists, an implicit subsidy through Increasing-Block pricing, and we're saying we're going to actually let you use it, apply it to some other time, and so it has further expanded this subsidy that fundamentally comes from Increasing-Block pricing and from pricing retail price that is set well above marginal cost.

I think that the fundamental problem isn't Net Metering, it's that marginal prices greatly exceed marginal cost, even including the social marginal costs that are imposed. I'm actually involved in some research right now at the Energy Institute to quantify these subsidies, including the subsidy from Increasing-Block pricing for solar PV, asking both how large are these subsidies, and also how are they distributed among customers of high income and low-income households. And I think I'll stop there. Thank you very much.

COMMISSIONER PETERMAN: Great, Severin. Thank you. I don't have any direct questions, myself, but I appreciate your presentation for providing some context into how our rate design currently is, as we move forward to talk about, then, how renewables will impact rates. And I think you've also touched well upon one of the areas when we think about -- because ultimately we're concerned with affordability, so how do we help with things be affordable, partly it's just reducing overall bills, and partly you can do that by reducing the actual costs of renewables, but there's also energy efficiency and other mechanisms that can be used to reduce overall consumption. And I think you've also highlighted some of kind of the nuances of Block pricing that might be exasperated by renewables, if you will. I did want to see if anyone had any questions for Dr. Borenstein, and he'll also sit on the panel, but it's a good opportunity now to ask. First, anyone from the panel with any questions? Anyone in the audience? Please.

MR. TRACY: Jim Tracy with SMUD. No questions, but I think that we at SMUD, we tend to agree with a lot of the comments that Severin just presented.

MR. SINGH: We do, too.

COMMISSIONER PETERMAN: We've heard a couple of "we do, too's" here. Do you want to particularly highlight something in the presentation that you want us to focus on?

MR. SINGH: When I give my presentation, I can touch on it.

MR. BRILL: I'll do the same.

COMMISSIONER PETERMAN: Okay. That sounds good. Well, moving along, I'll turn it over to the Moderator, Karen -- or unless we have any questions on the WebEx?

MS. GRIFFIN: Thank you, Commissioner. I'm Karen Griffin from the Electricity Supply Analysis Division. Thank you, invited guests, for being here today.

At the last minute literally yesterday we invited the utilities to give us a little bit of a background about their retail rates so that we could move through the discussion. The first thing is you may not read numbers off of your slides, but thank you for providing those numbers as background. And I'm going to ask you to do this in an order, I'm going to go PG&E, SMUD, San Diego, and Edison to round us up, and then we'll come back to the questions that were on your printed agenda. Okay?

MR. SINGH: Okay, good afternoon, everyone. My name is Amrit Singh from PG&E. So I will go through briefly about our rate outlook and I'll touch on some of the points that Severin touched on and we'll actually show how some of these subsidies play out in our rates. So with that, how do I -- thank you. So here what I have is what we're showing from our last IEPR Report, the 2011 data that we submitted, how our rates are projecting out, and you can see the red line there, if you can see it, it shows the inflation. And you can see for the near term, our rates are pretty much keeping up with inflation, but as we look out beyond 2015 or so, the rates tend to go higher than inflation. And what I'm talking about here is a system average rate for our bundled customers. If I were to show you similar slides going back to even as far as 1990, you would see that our rates have generally done very well, relative to the inflation. And what I've tried to do here on the green box that you see at the very top, is quantify using some approximations what the RPS, or the green power premium would be, and this is not the full cost of RPS, but this is, for example, if I were to compare RPS to MPR prices, which assumes a levelized cost for a new CC coming on line, how much are we paying more for RPS relative to that. There are other benchmarks I could have used, for example, forward prices, or where power prices are traded right now, and that green box would actually increase. So you can see that, in our rates, the RPS is starting to add to the cost pressure, and the reason is that we've signed a lot of contracts, but these will start showing up in our rates as they start delivering power. And in the past, we've benefitted for some of our lower priced renewable QFs.

So while this doesn't look like much of an issue from a system average perspective, even though it is adding close to two cents -- RPS is adding close to two cents in 2020, or close to two to three cents, depending on which benchmark you judge it again.

But if I go to the next slide and show you what's happening to residential customers, where we have a huge rate design issue, so this is our residential rate outlook, as well as I'm showing you a little bit of a history starting from the energy crisis. One note I want to make is -- and I think Severin touched on it in his presentation -- or maybe Carl mentioned it -- that customers, the bill that they get, what they pay is not just the cost, but it's also an impact of rate design.

So rate design, when we're looking at residential and a certain segment of residential customers, it's actually rate design that's having as much of a big impact on their bills as opposed to cost, and that's what I'm going to show here.

So prior to the energy crisis, you know, in California we used to have for residential customers are two-tier rate in planning block rates, same as Severin mentioned, you know, and the idea was that it encourages conservation -- I have to wrap up already?

COMMISSIONER PETERMAN: I would say. We have

-- we've got a little bit extra time from Severin's presentation, so please continue, but thank you for watching the time. I will override the time, but appreciate it.

MR. SINGH: So anyways, the energy crisis, five tiers were introduced, and this was to protect the low users and supposedly low-income customers. And for PG&E in CARE, we only had two tiers, so all our CARE rates were frozen, and any increase for nearly a decade all had to go to our tiers 3 through 5, and the impact of that was it led to a $0.50 rate when a cost of service is somewhere around $0.16. That black dotted line is our average cost of serving residential customers, and you can see how rates -- how far rates are removed from cost of service.

And the other thing I will add is, today, that upper tier where we're collecting most of the cost increases is only 23 percent of our sales, so another way of saying that is, 77 percent of sales that we're serving today is below cost of service.

And as Severin said, you know, people when they talk about IBR, they think about conservation. When 77 percent of your sales are below cost of service, it's hard to say that these rates are incentivizing conservation.

Similar to Severin, we did a study, we hired the Brattle Group and they did a similar study for us that showed that, in fact, going to a flat structure, marginally you would actually increase conservation because we have so much of our sales that is not subject to any price signals for conserving. So anyways, looking out, you can see the rates are going to skyrocket and this is not by any means a high cost scenario, this again is based on the IEPR data and this doesn't include some of the new policy goals that the Governor has talked about such as the 12,000 megawatts of DG, all of that will have, again, impacts on these upper tier rates. This doesn't take into account any disruptions you may get in the commodity markets, which are always very volatile, or hydro conditions, you know, we have a substantial amount of sales that we serve from our own hydro, and those can all spike, and if you remember what happened with gas prices in 2008, if we had any scenarios like that in the future, that would obviously exacerbate this problem. So as the slide says, this is not sustainable, this outlook. And when we talk about all these policies that we want to pursue, including RPS, if we don't address the rate design issue, you know, those policies are not really sustainable when we have to -- only 23 percent of sales to spread the costs on. And the unfortunate thing is that there's not much that PUC can do. As you can see, our rates came from close to $0.50 down to $0.34, approximately $0.34 right now, and that's from the limited actions the PUC could take such as lowering the baseline from 60 percent to 55 percent, which pushed more sales up, collapsing tiers 5 and 4 into new tier 4, and closing the gap between tiers 3 and 4. Going forward, they may lower it to 50 percent which is the limit, but there's not that much opportunity unless there's changes in the Legislature, or re-looking at changing SB 695, which was introduced in 2009, but it's not actually working as it was intended.

The next slide is basically, I'll go through very quickly and I’m out of time. Here is our CARE rates, you can see the CARE rates on average that we have today are lower than what we had in 1991, and that's nominal rates I'm talking about. If you were to look at the black line, if the rates had just grown with inflation, that's where the rates would have been, and if you look at the households, you know, it used to be seven percent of households, it's close to 30 percent of our sales, or 28 percent of households, that's in CARE, that's about a $700 million subsidy.

And the next couple of slides, you know, talking about customer charges, Severin talked about it, we have a lot of fixed charges, you know, our service is not efficient to recover everything through a volumetric charge. We are one of the few unique utilities along with San Diego who doesn't have a customer charge. There's a bill in the Legislature right now that will give the PUC -- it doesn't mandate the PUC, but it gives the PUC the ability to introduce one, and I think that would be good, you can see most of the California utilities have one -- Edison has a very small one because they had it before the rate freeze.

And the next slide, I show the average customer charges across the country. What's that?

COMMISSIONER PETERMAN: That's the average fixed charge?

MR. SINGH: This is the fixed charge, or customer charge, yeah.

COMMISSIONER PETERMAN: Great, thank you.

MR. TRACY: All right, I guess I'm next. I'll send a bill to PG&E for the time that he took out of my presentation.

(Laughter)

So my name is Jim Tracy.

COMMISSIONER PETERMAN: I'll take it out of my questions, so it's okay.

MR. TRACY: I'm the Chief Financial Officer with SMUD, and I'm the token economist on the Senior Staff and so when the CEO took over a few years ago, we restructured and the rates department came under me, so that combination with a public board where we have a very close relationship, the Board got to listen to a lot of interesting rate proposals that I was throwing out there along with my staff.

I would like to say that the issues of low-income, the Increasing-Block rates, the complexity of rates, these are all things that I will address at the appropriate time in the presentation. This just gives -- and, really, SMUD has embarked on some significant changes in its overall rate structures to try to achieve certain goals. This is just a depiction of kind of where our rate classes are, what types of customers we have, about half of our sales are residential, so it's a significant group for us. If you go to the next slide.

Basically, we've got a two-block rate right now, and I'll talk later about how that's expected to change. The low-income, again, I will talk later bout some of the adjustments that we've made to the low-income subsidy that, in our estimation, it's a better approach to low-income subsidies.

COMMISSIONER PETERMAN: Jim, I'm going to ask before you wrap up that you talk about them now, just to make sure we get it out there because I did want everyone to hear about the particular situation SMUD has gone through because I think it would be a good model for others to look at, at least consider, you've done a lot of work in the area.

MR. TRACY: Well, it's kind of wrapped up with the overall rate structure design for residential.

COMMISSIONER PETERMAN: Okay.

MR. TRACY: We are trying to reduce the difference between the two blocks, maybe at some point eliminate the different -- just have a flat energy rate, but we're moving those costs into an infrastructure charge, which right now we're at $10.00, but we're headed towards more like $20.00 in five years. And one of the concerns that the Board members had was, well, how is that going to impact the low-income customers? And as we had the discussion, one of the things was that the solar folks that were getting the subsidies off of the large block, when they did their solar, then those fixed costs got thrown back to the customers, and, you know, effectively there weren't any low-income customers to speak of that are doing solar. So, really, we had a situation where the Net Metering was disproportionately being thrown -- the costs were being thrown back to the low-income customers. There were concerns about the fact that, if we were raising our infrastructure charge, which is a fixed fee per month, significantly, how would that affect low-income customers who tend to use a little bit less energy? So the approach we took was, well, we're going to get more of our discount in the fixed charge. So if we're going to give a discount to low-income customers, just give it to them and lower the fixed fee upfront. What we would like to see is more of a price signal to the low-income customers that, you know, saving energy is going to lower your bill. So, with moving costs into the -- out of the energy and into the fixed charge, and giving them a big discount upfront, we took some of the discount that we otherwise would have been giving to the low-income customer and said what we're going to do is cut off the amount of energy on which they get a discount, so there's actually this third block where they get no subsidy. But that's where we're focusing our energy efficiency dollars. We specifically identify the three to five percent of our low-income accounts, and typically those accounts, they live in substandard housing, there's a lot of opportunities to save energy fairly cheaply, and we're focusing the subsidy dollars into energy efficiency measures that we basically just give to the low-income customers. We go in and change out a refrigerator, we do insulation, we do all their lighting, things that have very quick payback, so that we push them back in terms of their total bill goes down, but once we've done the energy efficiency, then we're not going to be giving them the discount year after year after year. And so that was kind of the approach is that, as we move forward, we're going to try to compress the low-income energy discount to something more of a lifeline amount of energy and focus energy efficiency dollars instead of on a discount into actual measures that will reduce their energy for the very highest users in that group. So that -- and, you know, we had a very long discussion with our board, and that's where we ended up and they're pretty happy with the results. And actually the low-income customers, it's been a very very good program because the very highest users, you have a big big portion of their income being taken up by electricity, those are the ones who are going into it and saying, "We're going to give you a free refrigerator, we're going to do this, and we're going to do that," and they're just floored, literally.

And then I think the last slide is just to talk about that we have on our commercial structures -- we are going from, with all of the AMI meters that we're putting in, we're basically putting all the commercial customers on Time of Use (TOU) so that they'll all be on that. And even on the residential side, we're toying around with electric vehicle rates where you might bring in a capacity charge for people who are doing electric car charge because, quite frankly, one of the problems that we see is that, if someone insists on having a 20 or 30 KW load or charger, you get two of them coming on at once, then you've blown the transformer in the neighborhood, literally, the distribution isn't set up for that. So the idea is kind of foreign to utilities to have a demand charge, or a facilities charge for residential customers, but we may go there as one of our options that we're studying for electric vehicles.

COMMISSIONER PETERMAN: Thank you. For those who may just be joining us listening to this panel, we're having each utility just provide a bit of information about their current rate structure and some of their considerations with renewables, but we also have a wider panel that will be raising issues and responding to what they've heard, and responding to questions from our moderator.

MR. BRILL: Good morning. Severin spent a lot of time talking about accurate price signals and the difference between the costs that utilities incur and how we incur those costs, and the prices that we charge customers. Before I get into the rate slides, and I know

I've only got three minutes, so I'll do it quickly, I wanted to go through the categories of costs that are actually reflected in our rates. It's really important to understand if you want to think about how you create an accurate price signal.

We've got customer costs, that's the cost to the meter, the billing system, the billing center, the call center. These are costs that we incur when a customer is hooked up and we send a bill to them, whether they use any electricity or not. We have distribution demand costs, these are the costs associated with our distribution system, they're fixed costs for the most part.

We build our distribution system to serve the maximum or the non-coincident demand of all the customers served off of the circuit. That's really important to understand because that's a different cost causation principle than system costs, or transmission costs. We build system capacity, or transmission capacity, to meet the peak demand of the system. So you've got distribution demand costs, we're building that to meet the non-coincident demand of customers served off of the circuit, and you've got system capacity; we incur those to serve peak system demand; and then you've got commodity costs and those vary on a Time of Use basis.

Residential rates are important because, when you think about the majority of our customers, they're on an all volumetric rate, it's not Time of Use driven, they don't pay fixed costs for any of those cost components that I just went through. Next slide.

This is the tiered rate structure that we have right now for our residential customer class, and I want to point something out. When you look at the top tier rate, that's $0.28 right now, a few months ago, that was $0.30. The way Net Energy Metering subsidies work, Severin mentioned Net Energy Metering; we avoid a cost of $0.8106 when a customer puts solar panels on their roof, or wind on their roof, or a fuel cell in their back, that's our time of day adjusted commodity cost. We do not avoid the remainder of those costs. We're now shifting about $0.20 of costs to other ratepayers. That's the Net Energy Metering cost shift and Net Energy Metering subsidy issue that a lot of folks have been talking about, but when you think about it, what we've really done with rooftop solar, and this is a key change to the industry structure, is we've unbundled commodity services from reliability services. That $0.28 rate, that's the rate for both commodity services and reliability services. That cost is avoided by a customer that sells supplies only commodity services.

Our small commercial rates are similar in one sense to residential rates, they're all volumetric. Most of these customers are not on Time of Use rates. The difference is that they are not tiered and -- if you could go to the final slide -- which is Medium and Large C&I, here we have a demand charge structure, we actually have a demand charge for non-coincident demand, that's to recover those distribution demand costs, and we also have a demand charge based on system peak demand, what's the customer's demand at peak, and that is to recover the system capacity costs. The majority of large -- medium and large C&I customers are on Time of Use rates, so they have the most accurate price signals of any of our customers.

MS. GRIFFIN: And I believe our Edison speaker is online?

MR. GARWACKI: Right. This is Russ Garwacki. I apologize for getting here so late. A lot of what you're going to hear, and I know I just got on mid-way through SMUD's presentation, so a lot of these are going to be very similar since California, San Diego, PG&E and ourselves, are all regulated by the same Commission, all of our rate structures and issues are going to be the same with some slight variations in degree, I suppose.

But moving on to just some of the rate design observations, you heard this probably four times by now, presented quite well by San Diego in terms of functional allocation, in terms of cost to serve, whether it's distribution, energy, or customer basis, as well, essentially with the advent of AMI, we're allowed to do a bit more Time of Use and demand metering for a variety of customers, and I'll talk a little bit about that in a couple slides. But we have a whole lot of regulatory restrictions primarily surrounding affordability and promotions of various technologies, and we'll talk about those with a little bit more detail now, why don't we move to page 2?

When we start looking at the tiered rates, as folks have represented, this looks a little bit of real world in terms of what our residential customers look like, in terms of CARE and non-CARE, and high vs. low usage customers, and you can see the degree by which the average rates and the average bills vary in the same residential space. On the far right-hand side, you can see what the various policy overlays have done, both in terms of affordability in the CARE/non-CARE space, and also in terms of an overlay of affordability and conservation incentive in the usage dimension, and you can see how the lowest usage CARE customers are paying under $0.10 per kilowatt hour with the high usage, non-

CARE customers paying $0.21 per kilowatt hour, and this is as of 12 months ending April or so. But you can see how the usage is distributed; that's not going to be any surprise to anybody. That will be probably very similar in concept to what PG&E and San Diego have probably already presented.

What you see is how it works to solar, and I focused these particular slides just to represent how the distributed generation impacts for NEM, in this particular case, what we did is we did an analysis of about 1,700 accounts that installed solar, both pre and post, their solar installations, and quantified exactly what the level of sizing is, and what the tiered retail rates that are actually offset, and what you can see is, on the top right, you can see our tiered rate levels for non-CARE, for the five tiers that we have in place, and that is weighted if you go immediately left of where the cursor is, the displaced energy, on average for these 1,700 customers, they're on average producing about 600 kilowatt hours per month, and offsetting the tiered distribution that you see there.

If you look at a weighted average of the displaced energy, you get to the far right-hand column of the $0.24, or the note that I have in red, that says that the average retail benefits for these folks is $0.24 per kilowatt hour, and what Tom had mentioned, in terms of the unbundling of gen vs. distribution, etc., with a gen avoided cost including capacity of about $0.8 per kilowatt hour, there's a significant subsidy going on there. When we start looking just at the average residential retail rate of $0.16 per kilowatt hour, the actual avoided retail rate, just because of the size consideration of these customers, is quite significant. The actual avoided gen cost component is about half of that $0.16.

When you move to the next slide, just some quantifications that we've run, when you start looking at the NEM subsidy, we're at about $50 million a year, a little over one percent of system peak, and that's currently defined as the system peak, the aggregated system peak, not necessarily the PD that President Peevey has issued, but that is the way we have proposed as zero, what we have indicated as the aggregated customer peak demand. And so, when you look at that times five, which is the current cap, that's about $250 million a year under President Peavey's redefinition of what that cap is, that essentially doubles that to about $500 million a year, so that puts some quantification around that.

If you move to the next slide, you see essentially what, you know, I didn't necessarily go into all the levels of details, but all the rate structures between ourselves and PG&E and San Diego are the same, residential tiered rate structure on a declining block basis, with uppermost tiers being about two and a half times the baseline rate, small C&I right now, energy only rate for the less than 20 KW customers. Right now we have a proposal before the Commission that we're litigating that talks about a Mandatory Time of Use. We're currently under an order from our 2009 GRC Phase II that says that you are going to have mandatory POU with default Critical Peak Pricing, we've opted to -- or we have asked to change that to Mandatory Time of Use with opt-in Critical Peak Pricing, a subtle difference, but that's how we're proposed it, the same with our Medium C&I, 20-200 KW, which is a Demand Metered rate currently. Our Large C&I, our greater than 200 KWs, we defaulted them to Critical Peak Pricing.

Back in our 2009 case in October of 2009, they migrated to Critical Peak Pricing and, just for purposes of comparability, we've got a little bit less than 40 percent of that customer base remaining on Critical Peak Pricing, for those who want to know that stat. And then the Ag customers, we're going to be looking at migrating them, as well, splitting them above and below 200 KW, as you see, as well, and offering some Opt-In Real Time

Pricing -- Quasi-Real Time Pricing, I'll say, it's not necessarily directly tied to the market because there's really, frankly, no significant differentials in the real-time market to justify any type of a load shift. So it's a manufactured rate similar to what Critical Peak Pricing is, which is we have certain triggers and we collapse capacity into some certain energy adders to instill some measure of demand response in that regard.

So those are the slides that I have, pretty consistent with my neighbors to the north and south.

MS. GRIFFIN: Thank you. As you remember, the whole purpose of what we're doing here today is to develop information and ideas for making strategic recommendations on how the state can move forward with its renewables programs in a cost-effective, reliable, safe, environmentally preferred manner. So this whole panel has two giant areas to talk about, one of them is system average rate impacts, what aspect of renewables is a portion of that, and a second one is the rate design issue. So I'd like to move back to the bigger one first, which is the system average rate in terms of moving forward. What proportion of the total kinds of mandates, things you need to do, including renewables, what portion of that is renewables? For example, I looked at a presentation L.A. gave to its Board, and they said that, of the costs they would like to incur to meet what they regarded as their mandates, 25 percent was RPS, and for them 3 percent was additional customer-side solar. Are those proportions -- and for them, I think about 30 percent was replacing their OTC fleet, so that was a big portion of theirs -- are those proportions -- what are the utilities seeing in terms of the total amount of rate increases you think you would like to have, if you didn't have some kind of overall, "My God, we can't do that" cap, would renewables be?

MR. BRILL: I'll take a crack at it. Someone has to do this. Sure, what we're looking at from the RPS is a total of about a two-cent system average rate increase, about one penny of an increase from where we are today. What's important when you look at those tiered rates, for us about one-third of through-put is the upper tier, so a two-cent average rate impact is six cents for those customers. Now, in the case of the RPS, we're actually buying something, and we're procuring renewable energy and we're adding that to our portfolio; it is equally important to consider the rate impact of Net Energy Metering.

Under today's rates, and by the way, the rate impact is very volatile, as is the magnitude of the subsidy, because the subsidy simply depends upon the level of the upper tier rate. If that rate goes up, the subsidy increases, if it goes down, the subsidy decreases. Our Net Energy Metering subsidy decreased by two cents when our upper tier rate went from $0.30 to $0.28. Later this year, when we have other rate adjustments, that subsidy is going to increase significantly. And so, there's no market reason for having that subsidy go up and down, month by month, and if you're to trace it historically, you would see that it's done that since it was created, those changes have no relationship to market conditions, no relationship to the need for a subsidy, no relationship to the cost of solar, and no relationship to anything whatsoever except for upper tier rate. But when you consider that, and that you're shifting the difference between that upper tier rate and the cost that we avoid, which is about eight cents, there's a significant cost shift. At today's rates, we're currently shifting about $16 million to $17 million to remaining upper tier customers with today's Net Energy Metering penetration levels. With higher rates -- and I can assure you, we will have higher rates as we move forward -- that number is going to increase materially. At a five percent cap, the cost shift under today's rates would be about $29 million, and the annual bill impact to an upper tier customer would be about $65 million.

MS. GRIFFIN: Okay, I want to stick on the topic of total system rates right at the moment because, if you look at the portion of Net Metering, in terms of the total renewable energy, today, compared to the proportion of energy we're trying to get from the rest of the renewables, the rest of the renewables swamp it. Now, we all know, and we're going to get to, the fact that the state is interested in increasing customer-side energy -- I mean renewables -- and how are we going to integrate that. But let's stay on the big prices right at the moment.

MR. BRILL: Yeah, but just one final point, because our customers care about bills?

MS. GRIFFIN: Uh-huh.

MR. BRILL: And so it's really important for regulators to understand that it's not just costs, rate design has a giant impact on bills. And so we can't only look at the cost side and, in the case of the cost shifts I'm describing, you have the least affluent of our customers subsidizing the most affluent, so those cost shifts are actually creating a real socioeconomic inequity. So it's not something that I would recommend we ignore.

COMMISSIONER PETERMAN: Thank you for pointing that out. Just so you know, I had a very good economics education, so I appreciate that.

MR. SINGH: It's sort of similar, I showed it on our overall system cost, if you look out in 2020, I think on a system average basis, it's somewhere around two cents, and that's subtracting out the energy value of RPS, just looking at the RPS premium, it's between two and two and a half cents, depending on how you value the premium. Again, tying it back to impact on customers in terms of residential customers for upper tier, rather than two cents, it's more like something between seven to 10 cents on the top marginal rate. So orders of magnitude higher for those customers because, you know, as we talked about, we are limited as to what we can pass through for the lower tier customers.

MS. GRIFFIN: Okay, and what percent increase are you looking at for, say, transmission or distribution additions?

MR. SINGH: You know, the number that I gave you actually accounts for the transmission that is associated with RPS, as well as an estimate of integration costs, so it's embedded in that.

MS. GRIFFIN: Imbedded in that, okay. Thank you. SMUD?

MR. TRACY: I think that the overall impact on our rates is probably something on the order of seven or eight percent by the time we have the projects that are in the queue for the next two years folded into our rates. It's by far the biggest component of the need to ask for higher rates from our customers over the next three to four years. I think most of our other components, we're able to hold those pretty steady.

I'd like to make a comment about, you know, as far as SMUD's perspective, I think that from a customer's perspective, the idea of bills vs. rates, we do want to focus on bills, but we can't forget the fact that, if you have a rate structure where, if you have a lot of energy efficiency happening, and you have a lot of fixed costs that are being collected through the energy charge, that those fixed costs didn't land on the rest of the customers in the system, so it's not just solar, it's the energy efficiency which we're trying to achieve, like one and a half percent a year, and that's a pretty significant amount.

And from an economic development standpoint, looking at our community, a lot of the commercial businesses that are coming in, you can talk about bills, but they're looking at rates because they're going to be -- they're looking at an efficient process already. And so what they're doing is comparing their process, which they're going to put in in SMUD's territory vs. PG&E's territory vs., you know, someplace else in the country. So we have to have a balance between the bills and the rates, themselves and part of that connection, that we had a discussion with our Board about, is the fact that if you can move rate structures over a period of time such that the energy charge and the fixed costs are being collected kind of in that manner through the tariff, then when customers make the decision to do energy efficiencies, if they make the decision to do distributed generation, the amount of cost shifting is minimized and, then, you don't have the utility having the incentive to discourage it in any way. We're actually a little bit -- if we can get that into that position, you're more Agnostic toward it, and it's probably a better environment for energy efficiency and distributed generation to thrive, even though it's more difficult for it to be cost-justified, because it's competing against a lower energy price; what is cost-effective, you know, should be done at that point. So, that's a big element of where SMUD is going with sort of some of their changes in overall rate structures to allow us to really be on the right side of the equation with the customer and say, "Yeah, we want more of that as long as it is cost-effective."

MS. GRIFFIN: Another of our panel members is also online. Stephanie Chen from Greenlining. Do you want to make --

MS. CHEN: Good afternoon.

MS. GRIFFIN: Hi. Do you want to make comments on these issues?

MS. CHEN: So I would say a couple of things come to mind. First, in continuing a series of lively conversations I've had with Severin about Inclining-Block vs. Time-Varying Prices, Severin, you mentioned that customers don't respond to Inclining-Block Pricing because they don't know how it works; well, the utilities haven't exactly done a bang-up job of teaching them how it works, and so I sort of wonder how people would respond to the Inclining-Block system of rates if they had not only the kind of monthly sort of temperature checks that you're looking at in Edison's bill redesign project, if I had understood your description correctly; but also sort of the ongoing input that I think is envisioned in a lot of the Time-Varying Pricing models -- this is where you're at today, this is where you're at this time of day for this time of year, and so on. So I think that, if you're talking about getting customers to respond to price signals, getting customers to be more efficient. The absolute make or break first step is going to be how effectively you're communicating information to them and providing those resources so that they are empowered to respond.

Another thing that comes to mind, I'm glad that folks have raised the issue of Net Metering because I think that, for the low-income constituencies that the Greenlining Institute represents, there's a difference in how we should look at those types of renewable projects that have socialized costs and socialized benefits, is kind of the way that I think about it, and those would be the utility-owned projects. Consumer advocates, I think, really like the distributed generation for a lot of reasons, but at the same time, the sort of utility-owned projects do have the advantage of having all the costs and all of the benefits kind of spread out over the whole customer base. And when you look at something like Net Metering, and to a large extent some of the challenges around EVs, and I think the gentleman from SMUD mentioned the transformers, these are programs where the benefits are largely individual to the person who makes the investment, but there are socialized costs in terms of either the subsidy question, when it comes to Net Metering, or some of the infrastructure upgrades that would be required to accommodate EVs, particularly at the scale that we are hoping to incorporate them. So I think that each one of these needs a separate consideration because I think that sometimes socializing the costs just may not be appropriate, sometimes it's a question of how well that CARE discount is working, whether it's truly providing affordability. But I think that ultimately what we need to remember is, while we definitely want to go after renewables and, while there are many statutory policies in favor of renewables, and I do believe that that's the way to go for the future, the affordability consideration is paramount, and all the renewable energy in the world doesn't necessarily help us all that much as a society if we are promoting energy efficiency by getting your power turned off because you can't pay the bill.

MS. GRIFFIN: Well, you bring up the subject of affordability. Do you have --

COMMISSIONER PETERMAN: Karen, before we move on, if you don't mind, I think Severin wanted to directly respond to a point that was raised.

DR. BORENSTEIN: Yeah, if I can just make a comment about communicating Increasing-Block Pricing, I would agree the utilities have not done a bang-up job at communicating it. I think that the bills prior to Edison's attempt at redesign work were completely incomprehensible to 99 percent of people -- some of that blame, of course, is on the PUC, as well, since that is jointly developed. But Increasing-Block Pricing is actually extremely difficult to communicate in a way that people can respond to it because -- I'm going to pick on PG&E, which now has this notification plan that, as you go to each increasing block within your billing period, it sends you a text message, and that is actually misleading because the real incremental cost of consuming at any point in time depends on where you expect to be at the end of the month, it's not that power is cheap for a little while and then you step up to the next step, we all know you're going to consume power on all 30 days of the month, and so to actually inform people, "Well, what's your incremental cost right now," it depends on all your assumptions so far in the month and all your expected consumption for the rest of the month. So I would argue that it is much more difficult to accurately communicate that to customers -- I would say pretty much impossible -- than Time of Use Pricing, or even Real Time Pricing, which people can understand that the price varies hour to hour, or between daytime and evening, and can adjust to, whereas this is, if not random, it certainly has this huge random component to it that the utilities really are not going to be able to communicate well, I think.

MS. CHEN: And you know, Severin, I see where you're coming from with that -- this is Stephanie again -- but at the same time, my concern, I think, is for people who have a hard time shifting that usage and having the sort of room to figure out when they're able to do certain things, when they're able to do the laundry, when they're able to run the dishes without incurring those increased costs. I think you get a little bit more flexibility in that. I'm thinking of, you know, workers who have got a couple different jobs over the course of the day, or workers who are working odd hours, and the only time they have to do laundry is during that peak, and so you're kind of just -- you're sort of stuck if the model is a mandatory one.

DR. BORENSTEIN: And I think we have to be careful about falling into the trap of people having a property right to whatever the current tariff design is. You know, the fact is that consuming -- running your laundry on the hottest day of the year does impose much higher costs on society than running it at other times, and I think it's important that, you know, and there are some people that win from that and some people who lose, my research has shown that it is not the case that poor people systematically win from having a flatter rate structure that doesn't reflect timing. And so I think moving towards a rate structure that does reflect costs should be sort of our default intent, unless you can show that it really does have a disproportionate impact on poor people. And in this case, yes, there are going to be some people who like to run their laundry, low-income people who like to run their laundry on hot days, and there are going to be other low-income people who don't run their laundry on hot days, anyway, and they're getting screwed right now by the current system.

COMMISSIONER PETERMAN: So I'm going to switch now to Jim Tracy signaling over here, he wants to make a comment, and then back to our Moderator.

MR. TRACY: I would just make a quick comment. You know, SMUD has probably tried for the last 30 years to tell its customers that it's a customer sort of run/owned utility, and we've managed to get the recognition up a little over 50 percent, so my point is you can't underestimate how difficult it is to send messages to a group of people who aren't that terribly interested in a utility, it's not that big of a deal for most people, their bill is small relative to their income. So it is difficult to get a message out to the customers that resonate with them.

COMMISSIONER PETERMAN: What was that message you were saying? I missed the first part? What was the message that you got 50 percent uptake on?

MR. TRACY: That we're actually a public utility and we barely have -- you know, maybe around 50 percent of our customers who actually know that, despite all of the advertising, everything we do. So trying to talk to them about something a little more complex than just "you have a public utility," we're convinced that you have to have very very simple rates, and so from that perspective, you know, a flat energy charge is probably better than an Ascending-Block charge, but we think that a Time of Use Rate, where there is consistency over the years, I mean, the worst thing you can do to the customer is, say, have them make decisions on a $20,000 solar investment and then dramatically change the rate structure on them so that, what they thought was a three-year payback is now going to be a 10-year payback. You want to talk about angry customers? I would be angry if that happened to me. So, simplicity in terms of trying to move to a Time of Use Rate where it's a real simple message, if you use power in the summer between 4:00 and 7:00, it's more expensive, it's cheaper the rest of the time. I mean, that is an easier message to get across and that is the consideration in terms of how effective your rates are going to be in getting customers to respond to them and participate, and then consistency over time so that customers feel safe about, based on this rate structure, can I make decisions which are the long-term elasticity as opposed to that short term, we're really focused on getting people to make decisions about equipment purchases that require investments, as opposed to behavioral stuff because that's where the big savings, we think, are going to be in the long-run.

MR. SINGH: Just real quickly, if I may? So I just want to say that PG&E has done a lot of focus group studies with customers and we find that most of our customers, it's very hard for them to understand our rate structure -- the five tiers, no one can actually compute the rate. So any time when we talk about dynamic pricing, we go to our next steps forward, we've got to fix the current system.

And the other thing that Jim mentioned which is very important is that we don't want to send the wrong signals to customers like who are installing solar, where their expectation is a three-year payback and it becomes 10 years. We know that the rate design that we have is unsustainable, it has to be changed. And change requires time, so we don't have time on our plate right now because the lower tier customers, we cannot have a rate revolt with lower tier customers, as well, because they're not used to rate increases. So we need as much time now to address all the inequities that have been built up in the rates.

And the other thing is that, when our rates are so different between CARE and non-CARE, where average CARE rate is around $0.096 and the top marginal non-CARE rate is $0.34, you know that customers who are making a few dollars above the CARE threshold, who are actually ending up paying those very punitive rates. So we've lost the, you know, balance in this.

MS. GRIFFIN: Okay, I'm going to go back to Stephanie on affordability and, after that, we're going to go to our other invited guest, Chloe Lukins from DRA.

Stephanie, you mentioned about affordability and I was interested in what kind of concepts go into that, again, thinking about, as we're trying to increase our renewables portion of our overall generation, sometimes we hear, "Oh, it's going to cost too much," well, how do you decide what is too much?

MS. CHEN: Hmm, that's a difficult question. And I think that there is the sort of aggregate question of what is too much, and then the individual question of what is too much. One of the measures that the CPUC looked at, I believe in 2007 in a report completed by KEMA, was energy burden and energy security, and looking -- that basically boils down to what percentage of your household income every month is spent on energy. And there's sort of an understanding among consumer advocates and other stakeholders in the industry that a certain percentage, maybe around six percent, let's say, is reasonably defined as manageable, and that of course being a percentage, it kind of fluctuates with your income level. Well, most of our low-income customers are well above that, and so I think that the more you get into 10 percent, 15 percent of your monthly household budget, going into energy, then the more likely it is that you're going to fall behind. So I think if you're looking at what measures of affordability, what do we need to look at, we need to look at that. I realize that we're never going to -- we're probably never going to hit the mark in terms of everybody having what is sort of universally considered to be an appropriate energy burden, but I think it's important to keep our eye on that prize and, as we're moving forward, see if we can stay as close as possible to that point. And if that point isn't reached, let's say, by the CARE Program, then what do we need to do to the CARE Program to make sure that it is?

MR. TRACY: Can I make a quick comment?

MS. GRIFFIN: Yes, please.

MR. TRACY: On affordability, I think that, you know, I guess from my perspective with SMUD, is that we can deal with the issue of affordability with the residential customers by tweaking the energy efficiency programs with low income folks with tweaking the discounts. I think one of the big issues around affordability that you have to keep your eye on is maybe the chamber of commerce should be doing exit studies on commercial customers that leave the state, and say, okay, how many commercial customers are picking up routes, moving somewhere else, as a result of, in part, higher -- you know, differential electricity prices? When you start seeing customers beginning to leave the state, that certainly should be one of the litmus tests because, if you have commercial customers leaving the state, talk about fixed costs that didn't have to be borne by residential customers who are still here, that's going to create a big affordability issue, too.

MR. SINGH: Talk about loss of jobs and, you know, would the CARE customers want a CARE subsidy or a job?

MS. GRIFFIN: Okay, Chloe?

MS. LUKINS: Thank you. My name is Chloe Lukins with DRA, and I work in the Procurement and RPS and Greenhouse Gas Cap-and-Trade area. And I just want to say, DRA does support renewables, but we want it to be cost-efficient. And hearing everyone talking, we all know that the prices are going to go up. Right now, about maybe a little over 50 percent of renewables are on line, and we are going to see the costs go up because more renewables are going to come on line. And you'll see one of the reports that the PUC put out recently, the 2011 Fourth Quarter Report, showing that -- you'll see that the costs now that they're being paid for contracts for generation that's coming -- renewable generation that's on line, and those that they're signing contracts going forward have increased quite a bit. So one idea to kind of bring out there is that I'm hearing a lot of people talk about the demand-side programs like Net Energy Metering, CSI, and distributed generation; and what would be good is that these demand-side programs really be counted towards reducing our overall electricity need, and with that, for reducing our RPS need and therefore our cost because I think you have to talk about RPS hand-in-hand with overall procurement.

COMMISSIONER PETERMAN: I just had a comment. You know, I agree, and you talk about RPS as part of the overall procurement and there was one of the questions that we touched upon earlier that gets to that, about the relative cost of renewables to other costs such as, for example, distribution upgrades, natural gas pipeline, upgrade safety, etc., and partly part of the discussion is making me -- this discussion illuminates that there are some challenges with rate design, generally, and trying to get a sense of how much of these are then going to be further driven -- will renewables add to the complication, or renewables -- something that's going on, but the complications exist whether we have renewables or not?

MS. LUKINS: I think that renewables, there are a lot of things associated with cost of renewables, there's the greenhouse gas cap-and-trade cost, also there's going to be the back-up generation, the fast ramping generation that's going to be needed, there's going to be also resource adequacy associated with the renewables, maybe some of the renewables may not have resource adequacy associated with it. And also, the transmission lines, which we've seen a lot of that already come on line, but there might be more that needs to come on line, too.

MS. GRIFFIN: Does DRA have a general kind of rule of thumb such as the one that Greenlining suggested about what constitutes affordability, either for the system average -- who doesn't exist to customer -- and for the low-income customer?

MS. LUKINS: Not that I know of, no.

MS. GRIFFIN: No, okay. Another -- I keep checking my list because I was enjoined to cover all the items on the questions.

COMMISSIONER PETERMAN: And can I just interject and say, you know, particularly on the issue of affordability, maybe we'll get back there, but that's something if any parties, both on the panel, or in comments, want to submit some suggestions about how one can look at affordability, that would be greatly appreciated because it is -- it comes up a lot and we are concerned with affordability, but we also want to think carefully about how to measure that.

MS. GRIFFIN: Another question that we had in this panel, Cost Containment was discussed a little bit in the prior panel on procurement, but are there rate design approaches that could be used to address some of the concerns about the cost of going to 33 percent by 2020? Anybody?

MR. BRILL: You know, one of the things --

COMMISSIONER MCALLISTER: I want to hear this, I was out of the room for the last ones.

MR. BRILL: Now I have to call you Commissioner to --

COMMISSIONER MCALLISTER: Yeah, exactly.

MR. BRILL: Thank you. One of the things about the rate design that we're talking about, the tiered rate design, is because upper tier rates are one-third of residential through-put, if you have a one-cent increase to system average rates, resulting from the RPS, and that would be an increase from today by the time we reach 33 percent, that's three cents for upper tier customers. And so it's really important from a rate design perspective to remember that, in the residential sector for us, because that's one-third of through-put and for each utility, it's going to be different, the multiplier will be different, but when you increase those residential class average rates by a penny, it's three cents for those upper tier customers. That's the kind of thing that triggers an awful lot of adverse consumer reaction, especially in a hot summer.

COMMISSIONER PETERMAN: I wonder if you can comment on, you know, looking at rate cases over the past however -- 10 years, or last few -- what has been the change in rates during those periods of percentage increase?

MR. BRILL: You know, I don't have those numbers at my hands, so I can't give you a specific number. Perhaps Edison or PG&E?

COMMISSIONER PETERMAN: Yeah, I'm just trying to get some perspective -- context. Any thoughts?

MR. SINGH: I think we have been generally in line with inflation, maybe lower than inflation, our system average costs, but as my slide showed, it's a different story for Res customers, for the upper tier customers.

DR. BORENSTEIN: And if I can add, I think that that's what's really driving PG&E's comment about sustainability and a number of other concerns, is that the costs of solar PV have come down partially because of real declines and partially because of really huge increases in Federal subsidies, to the point that it is now becoming privately profitable for some residential customers to install solar if they think that this rate structure is going to continue. And this rate structure doesn't reflect even close to the real costs to utilities, so back when we had these subsidies in 2005 and 2006, and the full installation cost was still above $6.00 or $7.00 a watt, not many people were willing to do it because they lost money at it, privately. Well, now we're getting to the point where people, some people, if they believe this rate structure will continue, could actually save money. And what the utilities, I think, are worried about is an avalanche because, at that point, if you start having a lot of people say, "Boy, this is actually -- forget about the environment, and forget about being green, I can just spend less on my energy bill," then you could really have a run on the bank. And then the fact that these rates do not reflect real changes in the cost of providing energy, makes it unsustainable; they never reflected the real cost of providing energy, but it was sustainable so long as not many people wanted to do it. And I think the fear now is we could get into a situation where I guess it's the dream of the Solar PV industry where it really takes off, and then just simple arithmetic says you can't cover costs.

MR. BRILL: There is one thing -- I'm sorry --

MR. GARWACKI: This is Russ Garwacki at Edison. You started talking about CPI and inflation adjusted rate levels. If we look back over the last 20 years, from Edison's perspective, we're probably about 15 percent below in terms of real terms in the system average rate relative to that which existed in 1990. And that will vary year in and year out, depending on whether or not you have DWR contracts coming in, or DWRE funds, etc., but the issue there is that the overall rate levels to some extent have been held in check, especially lately with some lower gas prices, but that still doesn't affect, you know, the upper tier differential that we're seeing. I mean, we still have a 2.5:1 ratio, at least for the non-CARE rate levels, and I would just echo what other parties have said is that, once we start catching up to inflation, if that does occur, we're going to have hell to pay once any type of a feed storm comes through; but in terms of inflation adjustments, that issue came up.

A couple other comments just because I had my hand up and I didn't know if the Moderator could catch it or if this was just a free for all, but when we start looking at tiered pricing, at least the focus groups that I've sat in on over the last year and a half, folks both in CARE and non-CARE customers, they understand the concept of using more and paying more. Now, whether or not they're confusing that with using more and paying exponentially more, I'm not sure if they clearly understand those concepts. But in terms of actual measurement, what we've done, and at least what we put in our 2012 rate case, is that we quantified what the impact is for the lower usage -- or lower income customers, and the fact is that if you're charging them less, lo and behold, their rate of increased consumption is higher than the non-CARE. So the economics is clear in that regard, and so then you have to start looking at whether or not this is strictly a temporal, by Time of Use, or whether or not that's actually holding through, through conservation principles, as well.

COMMISSIONER MCALLISTER: Yeah, I actually want to chime in here. So all these issues we've been talking about are interrelated and let's see, so on the one hand you have distortions related to, you know, arguably that the scale is arguable, but with Net Metering, for example, you know, you've got -- you know, Tom and I have talked about this a lot, where you have these tiered rates are sort of an artifice of legislation, and so I want to actually get some idea from the utilities how much they feel like, within the existing ratemaking processes, if AB1X, for example, went away tomorrow, how that would free them up to sort of fix some of this within the existing process. You know, my understanding is that the PUC at some point -- I'm not sure if Scott Murtishaw is on the phone -- but is likely to open an OAR on ratemaking, so that we don't have to have this discussion within rates -- within rate cases, but we can have them more out in the open and in sort of a forum that's meant to have this discussion.

So one question is just, you know, what it might look like if we untied our hands a little bit on the rate design process. On the rate structure, so the billing and the idea that customers have a hard time understanding their bills, I guess I agree with that, with what folks have said, that it's very difficult for the individual customer. I'm wondering, though, about the contractors, I mean, some of them actually have proven quite sophisticated to offer the right system with the right value proposition for a given customer. So they clearly have figured that out. And, granted, there is some fat in the system with Net Metering being the way it is, and the tiered structures and everything, so it's not that difficult to make a very solid value proposition to a given customer, but I feel like the danger in sort of renouncing the aggressively tiered structures too quickly, or the existing structures, I should say, too quickly, is that we would sort of push the solar industry, or push DG off a cliff and say, okay, well, we're going to end Net Metering as we know it, but then we're not going to have anything to sub for it, or to have a continuous sort of tapering off of that industry. And that would be sort of the worst of both worlds. So anyway, any comments on that, because what is the alternative to Net Metering, given that we're talking about the FIT, we're talking about all these other things, what is some medium -- intermediate ground that can allow for a value proposition within the changed market that's been referred to, right, we have lower costs, we have a lot of advantages that we didn't have a few years ago when all these programs started. But if -- you know, the end result can't just be, "Okay, we're going to get rid of these distortions from one day to the next," and then let the chips fall. I don't think that's acceptable, either. So hopefully the PUC can manage that discussion in the OIR and we can help in the IEPR process, or otherwise, facilitate this discussion. So, Severin?

DR. BORENSTEIN: Well, first of all, Commissioner McAllister, I think you were out of the room when I gave my presentation, but I made this distinction between Net Metering and Increasing-Block Pricing that I think is very important. And I think that -- I should say, no one things we should get rid of Net Metering, but I think it would be pretty easy to convince people Net Metering is not a big issue if we didn't have Increasing-Block Pricing. It's the Increasing-Block Pricing that's creating the problem here. And I'm pretty hesitant to go down the road of saying, "Yeah, we all know this is a structure that doesn't have anything to do with cost, but we should keep it to keep the solar industry alive." If we want to keep the solar industry alive at high cost, we should, I would argue, be more transparent about that and say we're going to charge for electricity, what electricity really costs, or something closer to what electricity really costs, and we're going to incentivize solar directly and recognize those costs. Because all we're doing right now is hiding them.

Now, I guess I'd like to hear how SMUD handles this because SMUD, first of all, has a much less aggressive Increasing-Block structure, and do -- and maybe has much more aggressive solar subsidies because SMUD also has a lot of residential solar PV that's still getting put in, don't they? Even at $0.18 peak, or highest tier.

MR. TRACY: Well, some of the things that SMUD has tried to do, like the Solar Shares Program, where we simply said, you know, the economies of a more commercial size installation, and then we effectively do a pseudo-bill, you know, so we take the value -- or the output of this facility, and we give customers the credit as if it was on their rooftop. And there's probably 40 or 50 percent of our customers who are not really well situated, either they are apartment dwellers, they have shade trees, the roof is wrong, the orientation is wrong, that can't really participate in the SB 1 kind of programs as they were originally designed. So SMUD has tried to be pretty innovative to work with its large customers and develop that, but one of the things that is interesting about the whole distributed rooftop solar is, you know, I question in the long run whether all of the costs associated with the small rooftop solar is yet to come home to roost. SMUD very early on had programs called the PV Pioneers, and we had all these rooftop solar, and it cost us almost as much to deal with the customers at the tail end of that program because of people complaining that the attachment was ruining their roof, and they had a leaking roof, and what do you do when your roof has to be changed out, and you've got the solar facility on top, there's extra costs associated with that, are the contractors going to be responsible for that cost or not?

You know, if the costs weren't -- I mean, if it's a cost benefit for the customer, fine, I'm not necessarily a huge fan of rooftop solar for residential. I think it works much better for commercial buildings where you have flat roofs and they have roofs that are more adaptable to solar, to smaller one to five megawatt installations around the system, that type of distributed solar. So it's just an interesting whole value proposition out there as to how much you really push the residential retrofit market.

DR. BORENSTEIN: Yeah, at the risk of sounding like a shill for SMUD, I think this is a great example of how taking out the implicit subsidies and making them much more explicit leads to better policy because, when you make it explicit, it becomes clear that, if that's what we're trying to do, oh, here's this alternative way of doing it, of putting solar where it's actually efficiently installed, not on the residential rooftop, but letting people essentially have a contractual relationship with the solar, gets you the same amount of solar and does it much more efficiently. But you're not going to get that if the only way people can do it is by putting it behind their meter, which is how we do it now.

COMMISSIONER PETERMAN: I wanted to mention, well, I think Tom is going to make a comment, but then after that, if Stephanie -- I know you're on the line, it might be hard to interject on WebEx, but if you had any comments. But let's hear from Tom first.

MR. BRILL: Yeah, I'll just make a couple of comments. You know, the State obviously has a Net Zero Energy Construction Policy, and it makes sense, I think, for us to step back for a second and think about, in that type of world, what services would those buildings and homes require from utilities, and to utility rates, where rate design currently allow utilities to charge for those services, that they will require is reliability services. Currently, utilities are not allowed to charge residential customers for reliability services. And if you go back historically when we unbundled or deregulated the price of natural gas at the wellhead, and we started to implement that through FERC Order 636, we unbundled the price of interstate transportation from the price of commodity, when we did the same thing in California under the CPUC's Capacity Brokering Proceedings, we unbundled the price of commodity from distribution rates. When we did the same thing, gave customer choice on electric commodity purchases from central station resources through a marketer under AB 1890, we unbundled the price of commodity from the cost of transportation because we were trying to get accurate price signals to customers, we have yet to do that in the rooftop solar market. And in that market, the reason is that what we're unbundling is not the transportation service that we all understand and accept and easily are able to grasp with, what we're now unbundling is something we've never charged for before, reliability services. We never charged before because generation was central station on the other side of the meter, so no one ever thought about T&D costs being used for this new thing called reliability as opposed to transportation. But if we want to have Net Zero Energy Construction Policy in California, we're going to have to make sure that the utility business model and rate design structure is designed to support it so that utilities can sell the services that those customers will need, and those customers know that they have those services available. If we do that, there will also be a price signal so customers can consider distributed electricity storage as an alternative to utility services. Today, they have no price signal with which to do that, but with that unbundled price signal, we're going to actually encourage innovation which currently is being stifled by the lack of that price signal in the retail market.

COMMISSIONER PETERMAN: Tom, this is Commissioner Peterman. I think those are all very good points and I will expand, though, that I think we need to consider what the right rate structuring utility model is for the host of clean energy goals that we have, because when we think about transportation, electrified system, vehicle to grid, possibly having customers providing their own storage, again, there's going to be different models, especially as we pursue generally DG goals, whether it's solar PV or small wind, there's also challenges with utilities currently either sometimes having zero load growth, or even negative load growth, you know, how do you price that? How are you thinking about reliability when you're encouraging the DG, but you're not having revenue to offset that? So I think that's all very general and good points.

MR. BRILL: And just to echo with what you're saying because, you're absolutely right, all the policies embraced in SB 17, the Smart Grid statute, really envision this end-to-end system that will call on resources behind the meter for capacity ancillary service commodity, whatever, all the way up to central station resources. To make that type of end-to-end grid work in a seamless, least cost, lowest emission manner, you're going to have to have price signals on an unbundled basis because that's thousands of transactions a day. It's much like locational marginal pricing on the transmission grid, you can only really achieve that vision with accurate unbundled price signals to run it.

MS. GRIFFIN: You wanted to turn to Stephanie?

MS. CHEN: Thank you. This is kind of an interesting conversation and it sort of mirrors the conversations that have been going on inside our office of late. As low income advocate, on the one hand, net metering and distributed generation, you know, if you get an installation through the SASH Program from Grid Alternatives, that's one of the best affordability measures we can provide because you are generating some of your own usage, you're reducing what you're pulling down from the utilities, we think that's fantastic. The problem is, as has been acknowledged by other panelists earlier, not everyone is in a position to do so, and it doesn't just have to do with the CSI subsidies, for example, which are largely enabling, I think, most of the residential solar installations that are going on in the state today.

Once those go away, or if you're not -- if you are a renter, if you won't have the right kind of roof, it if doesn't face the right way, if you've got too many trees, things like that, you're just not well-positioned to kind of DRY in the way that Net Metering encourages and, you know, there's been much talk about the cross-subsidy that comes up from Net Metering, and I think this is definitely something that sounds like the PUC is going to be considering among its other things when it engages in the rulemaking that has been promised. But what I started to think in all of this, Commissioner Peterman, you mentioned that there are going to be so many different models for different kinds of customers, customers who invest in DG, customers who buy an EV, customers who purchase some sort of other storage for themselves to better take care -- to better utilize, I guess, maybe the solar that they're putting on their roof.

With all these different models, I think it's going to be very easy for all of us who are -- let's be real, energy nerds -- to overlook the just simply want and need to relate it to the utility in largely the same way as they have been. They're not getting into any of the fancy new technologies, they're just trying to use responsibly and keep the lights on. And so I worry that in the quest to design the perfect set of systems for very sophisticated energy customers that we will lose sight of -- or treat as an afterthought the customers who just aren't energy savvy in that way and don't want to be. I mean, these are customers who understand that conservation is good, either for the environment, or for the wallet, or for both, but they're not going to be getting all tricky with their energy use, and I think that we need to -- we need to make sure that we're taking those into consideration as this starts to get vastly more complicated.

COMMISSIONER PETERMAN: I'll just note, I think that's a good point, I'm just sitting here thinking about phones and how, even though I really admire iPhones, I don't really want one because I don't have the dexterity to do the sliding and all that jazz, but it's very easy to get yourself a basic dial-up phone, still, but it's harder to do something with the equivalent range in the electric sector, and there goes the problem.

MS. CHEN: Exactly, and I think -- I'm sorry, the question of the iPhone uptake is a big one, too, because I think, as we're talking about some of these different rate structures that we're looking at to help bring the cost to the customer truer to the costs to the utility, a lot of them rely on that kind of instant information, and if you don't have a Smart Phone, or you don't have text messages on your cell phone, that could be a real issue for you and make it very hard for you to save money as you need to on some of these time varying rates. I think one of the fun examples is, ask everyone in the room, and unfortunately I can't see everyone, but ask everyone in the room who has got a Smart Phone. We're not designing policies for the people in the room, we're designing policies for the people outside the room, and I think we just need to remember that.

MR. GARWACKI: This is Russ Garwacki. Following up on what Stephanie just mentioned, I think she's dead-on right because, when we start looking at the number of NEM customers that we have, for example, we're probably at about 35,000 installs on the residential basis, yet we've got 4.2 million residential customers. So when you do a percentage basis, we're really managing to a very small segment of the population and I know my marketing -- or I know the marketing folks at Edison will shoot me, but most people don't wake up in the morning thinking how they're going to expand their relationship with Edison.

[Laughter]

They want to get through the day. They want to get through the day. You know, but case in point, I mean, not to let this one particular section dominate the policies, and I think somebody raised up the issue of you know, throwing solar off a cliff, if we modified the rate structures. One of the things I would suggest folks to do, and maybe we'll put it into comments at some point in time, is what I have drafted up is PG&E's Cumulative Installs for Solar, and that's all online from that California Solar Statistics, which is a really cool website if you haven't looked at it, but when you track the solar installs on a cumulative megawatt basis, and you put some lines in as to where their summer initiative went from a $0.50 top tier down to a $0.40, and then ultimately to a $0.30 top tier rate, which on a cents per kilowatt hour basis, is huge, they've undergone some very dramatic changes in their upper tier rates, and it hasn't affected the trend line of solar installs one iota. And so, if any time is a good time to effect change in this regard, it's probably now while the trend line is moving up, let's go ahead and capitalize on that trend line while we can. I think that would be useful for at least parties to look at, and that will probably show up in some papers in the near term that I looked at putting together.

MS. GRIFFIN: I'd like to turn a little bit to commercial and industrial rates since they are more than half of your total customer base in terms of usage. Do you think that the commercial and industrial rates that you have now are incent, disincent, or are neutral on both customer-side renewables and the amount of grid-side renewables we're adding?

MR. BRILL: All right, I'll do it again. I'll do it quickly. For large -- for medium and large C&I customers, for us at SDG&E, we've got very accurate price signals, we have a demand charge structure with non-coincident demand charge and system peak demand charge. That has a very accurate price signal. For all of our other customer classes, we have all volumetric energy rates, those are far less accurate price signals. We've got about 50 percent of our Net Energy Metering penetration in C&I markets, and about 50 percent in residential. So we're not seeing clear evidence that more accurate price signals are harming that market, although in my own mind right now, as I speak, I'm not recalling how much those installations, or medium and large C&I compared to small C&I, so there may be some additional research that's warranted.

MS. GRIFFIN: That's interesting, I hadn't heard that before, that half of your Net Metering is on the commercial industrial side. Is that the experience of the others?

MR. SINGH: Yeah, it's the same for PG&E, we have -- I don't know if the split is exactly 50/50, but we have pretty substantial on the commercial side, industrial side.

MS. GRIFFIN: And in your rate cases, or in DRA, do you all hear cross-subsidy arguments within those sectors? Or are they all -- okay, fine.

MR. SINGH: I think all customers are concerned about the cost, so obviously they want to keep the rates down and keep rates competitive, and stay in California. They do engage in rate cases on subsidy issues, but the biggest issue that they have participated, at least in our recent rate case, actually, was the CARE subsidy because, you know, that's a $700 million subsidy and a good chunk of that is picked up by non-residential customers.

MR. TRACY: I was going to say that, in the SMUD service territory, the vast majority of the SB 1 solar that's happening right now is commercial, even though it's a lower price, the equation of people putting it in, because they're bigger installations, it's more cost-effective. We have more commercial installations. It was kind of interesting, though, prior to the recession, I almost forgot about this, but our residential was cooking along pretty well because we worked very hard with all of the housing developers, the Lennar's and the large home builders. And we actually arranged contracts for them to do sort of the low use, Net Zero kind of communities where, you know, every house they built in a subdivision would have solar integrated into their roof, which made it much more cost-effective if you were planning a Greenfield residential community, you could get the orientation, you could design it so the solar worked and it was a lot cheaper. We had signed a lot of those, and then when the recession hit, I think we'd been averaging about, you know, less than 200 lots per year for the last five years, so I'd kind of forgotten about that.

DR. BORENSTEIN: Yeah, if I can -- I think you're not going to see this concern about cross-subsidy in the C&I because you don't have Increasing-Block Pricing, and can't in C&I. And so the big cost subsidy is not the Net Energy Metering, it's the Increasing-Block Pricing, and the marginal rates that C&I customers face, particularly the large C&I customers, are much more reflective of true energy prices, and so when they put in a big solar, they're still getting a huge cross-subsidy from Federal tax revenues, but they're not getting it from other ratepayers.

COMMISSIONER MCALLISTER: I'll chime in and agree with Severin on that. In SDG&E territory, where in a recent former life I did a lot of analysis, and knowing what the CSI looks like, I mean, Stephanie said a little while ago that, if the CSI has been driving the marketplace -- actually, that's been a while since that's been the case; really, we're talking about accelerated appreciation and Federal subsidies, in addition to the Net Metering incentives -- or the Increasing-Block incentives, rather. But in the C&I customer base, basically the project flow for solar is stagnant because it's right at the margin of what's cost-effective -- what's really doable, what pencils out. You've got some contractors that are making it work with some fairly optimistic assumptions, some of which are happening and some aren't, but really, it's a completely different marketplace than the residential, so I think a lot of what's driving this discussion is the residential marketplace and not so much the commercial where things are, actually, a lot more transparent and sort of rationally understandable.

DR. BORENSTEIN: And if I can just add, I think that's a real shame because the C&I costs really are much much lower than the residential retrofit costs for solar, and so if we wanted to do solar in a way that minimized costs, but increased renewables, it makes a lot more sense to be putting them on the rooftops of Wal-Marts than to be putting them on individual houses, some of which face the right direction, and some of which don't, but because of the rate structure, we're tilting it the other way.

COMMISSIONER MCALLISTER: Well, there's also -- so I would call out schools, as a place where it will be interesting from a social perspective, and also from sort of -- it's generally a non-residential C&I type tariff that they face, so that's a place where you could kill a lot of birds with one stone, so to speak. Yeah, but there may be other social reasons to want to allow participation in some way in California for people to put solar on their roofs, but, again, that's a calculus that's better -- I agree with you, that's a calculus that's done hopefully with information and out in the open, rather than sort of implicitly behind the scenes.

MR. GARWACKI: This is Russ Garwacki. Just to put some junk math around this, when we start looking --

you asked what the split was between C&I and Res, and the numbers that we see, at least current installed, is about 60 percent of the installed megawatts at C&I, and about 40 percent Res. And so that's the installed component. When you start looking at the NEM subsidy component, it's about 7:1 ratio in favor of Res. And so that just tells you how upside and how different the rate structures are -- and transparency was mentioned -- between C&I and Res.

Now, the other part that has come up in a few of our cases, in a few of the IOUs cases, is this notion of an Option R rate where what some of the solar installers have done and lobbied successfully in our case, what we've done is we've looked at the resulting load profiles associated with customers after they've installed solar, and obviously the solar load profile during the day reduces somewhat the demands coincident with system peak, and somewhat coincident with circuit peaks. And so that's reflected in the rates. And so those types of things can be done fairly straightforward -- much easier on a C&I basis. The utilities have that type of control available to them, which just eludes us on the residential side.

MS. GRIFFIN: Okay, one of the questions that we haven't touched on is timing in terms of where we're going to be paying for our 33 percent renewables, and our

DG, and our transmission, and distribution. Is this just going to add on a little percent every year? Or do you see that there's a huge wave of costs coming right now? Or maybe there's a wave coming at the end of 2020 and beyond? When these things are coming on line, does that have an impact that flows through immediately into your issues about how to best design your retail rates up through 2020, say?

MR. SINGH: Yeah, I think I gave a little illustration of that in the overall system average chart that I had, where you can see that they're starting to roll in now because that's when most of the contracts are starting to deliver, and then it does increase going forward into the future years. So that's more of a reason why we need to address a rate design issue because, now, instead of beating inflation, we're seeing rates actually growing higher than inflation.

COMMISSIONER PETERMAN: Anyone else?

MR. TRACY: Yeah, and I think SMUD's concern is that, when you're talking about the whole rate structure, the renewable portion of it is just a piece of what drives rates, and what we've been seeing in the last three years is a substantial reduction in cost of service from natural gas. Now, there's, you know, you can talk to 10 people and you get 10 different answers as to where natural gas prices are going to be in five or 10 years, but they aren't going to be at $2.00 and $3.00, that's not sustainable for the industry. They're probably going to be north of $4.00, you know, it's basically whatever the replacement cost of shale is, and that's probably in the $4.00 to $5.00 range at some point. But when -- actually, for most of the utilities in California, natural gas prices have more impact on rates than do the renewables, and so you know, policies around how we phase in or procure our natural gas, you know, if you're procuring natural gas on a year-to-year basis, that can have some pretty significant oscillations in overall utility costs and rates, as opposed to maybe paying a little bit more and procuring out three or four years. So, I mean, you know, for SMUD, the renewables are a component as of right now, at least in the foreseeable next three years, is the primary driver of the rate increases that we're going to be looking at.

And, you know, the thing that SMUD does differently than the private utilities is that, when we go to change our rates, and I don't look forward to it at all, but the senior staff has to go out in the community and we have well over 100 meetings with the Elks Club, with the Chambers of Commerce, to give presentations on, you know, what's driving rates, what the change is we're making, and those are things that we talk to the general public about. But, I think there's this element of just what is the rate that is being foisted on the consumer, but how much information is going out there to explain what's happening is a really important thing in terms of customer relationships and customer acceptance of what's going on.

MS. GRIFFIN: That's a nice segue into the next element which is asking the audience --

MS. LUKINS: I have a comment, if I could just make a comment on that?

MS. GRIFFIN: Chloe, please.

MS. LUKINS: I agree that I think that the RPS contracts are a small percentage of the revenue requirement. We estimate about maybe five percent RPS compared to the revenue requirement. And the revenue requirement is what fees -- I missed the benefit of Severin's talk, but the revenue requirement is what goes into the rate design.

The other thing is that we won't see the rates, or the rate impacts, until the generation comes on line, so maybe about 50 percent of the renewables are on line, so we have another 50 percent that's going to come on line, which will happen between now and 2016. So we will see a rate increase on that, but, again, to reiterate, I agree with SMUD that it will be a small percentage, and I was just looking at the Power Purchase Agreements for renewables, however, again, there's the other procurement that comes into play like the back-up generation for renewables of transmission, the utilities' administrative cost to run these RFOs for renewables, and to manage the transmission lines.

COMMISSIONER PETERMAN: Thank you for that. I think, you know, you're right that we haven't seen yet the impact of the bills from meeting our 33 percent RPS target, which is why we're going to have this conversation now, to talk about is there a way to both communicate those potential rate impacts, as well as to reduce them. I think Commissioner McAllister had a question.

COMMISSIONER MCALLISTER: I just wanted to ask DRA, does DRA have a position on sort of the ratemaking issues that we're confronting and whether the PUC, you know, well, what role the PUC could play in sort of, you know, sorting out this issue of perceived or real distortions in rate structures with respect to -- well, really, the ratemaking process?

MS. LUKINS: Well, DRA -- we know that the Commission is going Time-Varied Rates, and we are advocating for the Time of Use, more so.

COMMISSIONER MCALLISTER: Uh-huh.

MS. LUKINS: And that's all, really, I could comment on right now about that.

COMMISSIONER MCALLISTER: Okay, but you would be ostensibly participating in that rulemaking if and when it comes around?

MS. LUKINS: Right and other -- right, and others (indiscernible).

COMMISSIONER MCALLISTER: Oh, great. And also, I wanted to ask Jim, so natural gas prices have gone down, you know, the last couple years, and they're historically low, you know, they may go lower, but I don't understand exactly how that could happen, but it might happen, have your rates gone down? What portion, you know, fuel costs, have they allowed you to actually reduce rates? Is there an adjustment there that customers are benefitting from as a pass-through?

MR. TRACY: Well, at SMUD, we do procure our gas a little bit differently than the other utilities in the state. We typically do sort of a rolling purchase so that we are locking in gas sort of on a 24 to 36-month basis out. So when gas prices go up, we don't see our costs go up all that quickly; when prices come down, the bad part of it is our costs don't go down as fast. But having said that, the lower gas prices that we're seeing now are beginning this year to roll into our contracts and will be over the next couple of years. So what that's really done is not allowed for a rate decrease, it's allowed for a much smaller increase, so it's offset most of the costs of a couple of things that we ended up doing, one of them is at the front end of the recession, we had sort of restructured our debt so that, you know, we wouldn't have rate increases due to increasing debt service requirements. And we certainly put like a four or five-year window in there and now here we are, the economy is roaring along in Sacramento, and our debt service is stepping up over the next couple of years, too, it's kind of long term level. So there's some increase there, but the other piece of it, we knew that we were probably going to have about a seven percent overall increase from a couple years ago through actually getting our full 33 percent renewable in place, and it's allowed us to offset part of that increase, is effectively what's happening over the next two years.

MS. GRIFFIN: Are there any comments from the audience, people who want to join in?

MS. LUKINS: Can I just make one last comment?

MS. GRIFFIN: Sure, Chloe, go ahead. Oh, no, go ahead, go ahead. Sorry I didn't see you.

MR. PIERPONT: Brendan Pierpont from Climate

Policy Initiative. I noticed that you guys kind of got back a little bit to the Cost Containment issue. And I wanted to bring up kind of one point that I saw in a number of other states, particularly with the type of one or two percent rate impact limits that were put on policy. In a number of cases when those constraints weren't consistent with the overarching policy goals, the renewables targets, there were often kind of signals that the regulators and the utilities were more committed to the target, rather than the cost constraint. And because of things like ambiguity and how these things are calculated, and uncertainty and sort of what counts, what doesn't, the costs ultimately sometimes exceeded the intended limit, and so just in terms of how Cost Containment is implemented, it's important that it's consistent with the policy goal. So talking about all these affordability issues, it makes me wonder a little bit kind of these discussions should probably be taking place at the target setting level, rather than the implementing level, because it seems like, in a lot of cases, there's a bit of a disconnect.

And a second point around Cost Containment is there's often a lot of uncertainty and I think this is something that you guys are bringing up a lot here, is what's the baseline that you're comparing it to. Right now, our baseline is very low natural gas prices which makes the incremental costs of renewables look much bigger than it did maybe five years ago. So just a couple thoughts from other states that I've looked at.

COMMISSIONER PETERMAN: Thank you. A quick follow-up question, Brendan. You talked about this work you're doing, doing a survey of the various states and looking at Cost Containment, where will we find this work? When will it be available?

MR. PIERPONT: So a report that is actually targeted towards the California audience should be available on our website shortly. You can also come to me and I will get business cards and email it to whoever is interested in taking a look at this -- it's not published quite yet, but I'm happy to share it with whoever is interested.

COMMISSIONER PETERMAN: Well, if it is published before we close out this IEPR proceeding, then please submit it to the record, otherwise we'll come for a sneak preview.

MR. PIERPONT: Thank you.

MS. LUKINS: May I ask, are you participating in the RPS OIR at the Commission -- they're talking about Cost Containment?

MR. PIERPONT: Not in any formal way. Part of the reason for the work that I've been doing is because of the interest in the requirement that the CPUC would be developing, a cost limitation for the RPS, but I think that any kind of recommendations and statute are going to come from staff. But I have been talking with Paul Douglas and Jason Simon, but on this, so --

MS. LUKINS: Okay, I'd like to get your card, too.

MR. PIERPONT: Yeah. Thanks.

MS. LUKINS: Well, just a comment on what he was saying about Cost Containment, obviously we know that if we have Cost Containment, it will keep the rates down, and it kind of didn't work so well in the past with regards to the AMF, the Market Funds, so right now there's the RPS OIR that's happening with the Cost Containment.

MR. TRACY: I would say the one thing that I definitely agree is that Cost Containment really starts when you set the policies. Once you've set the policies and you have to go out and procure the resources, all you're doing is molding the costs around, so that, you know, it's pretty difficult to kind of envision Cost Containment when all the costs have been incurred. You know, from SMUD's perspective, if we were looking at the individual consumer out there, and I see a premium that we're paying for the renewable energy that we're buying is, you know, $75 to $80 million, and we're spending $35 million on energy efficiency, yet we're making more progress towards reducing customers' energy use through energy efficiency, what's a better deal for the customer? Well, it's clearly money spent on energy efficiency as opposed to the renewables. And you know, you have to decide what is the real policy goal -- 33 percent is not a policy goal, it's a way of getting to a policy of reducing carbon. And so you have to look at what are the real policy objectives and then give utilities more flexibility in determining how the most cost-effective way is of achieving those policy goals.

MS. LUKINS: Just to kind of add to his comments, kind of reiterating that if we look at all these demand-side programs and we actually count them towards reducing our need, I think that would help reduce costs because, right now, in the Long Term Procurement Proceeding at the Commission, that's what is being litigated, but what is considered reliable? What is the amount of energy efficiency that's going to be counted towards reducing demand? What is the CSI? You know, what is the distribute generation that would be counted towards reducing the need? So I think it's really important to make sure that that's accounted for, so we are reducing what we really need, and that all these programs that are being subsidized are actually being accounted for.

MS. GRIFFIN: Lynette, is there anyone else on the Web?

MS. GREEN: There's no comments from the Web. I would like to open up the phone lines.

COMMISSIONER PETERMAN: I think there's one more comment in the room. Do you want to stand up, sir? And then if you want to open up the phone lines, great.

MR. SILSBEE: Thank you again. I'm Carl Silsbee from Southern California Edison. At the outset, let me thank the Commission and all the staff who have helped organize this series of workshops on Cost Containment issues. They're obviously very important things for us to worry about and I think the Panel 3 discussion, talking about the distortionary impact of the tiers and residential rates, and the uneconomic bypass concerns that we face, and may face to an even greater extent if natural gas prices go up, and cause kind of the multiplier effect on the high rates to drive an imbalance between what Professor Borenstein called the "private cost vs. the social cost," or private benefits, I guess, vs. the social benefits of the solar programs, I think are very important.

Another element of the high rates issue is the effect on the California economy and, obviously, higher rates do have a negative influence on business competitiveness and jobs and economic growth. There was a study that was done for the Commission, I think it was in the 2007 IEPR that looked at the economic effects of the Self-Generation Incentive Program that was in, in some sense, the predecessor of the California Solar Initiative. And what that study found is that, although there was an increase in green jobs as a result, overall, SGIP reduced jobs, so you had higher income green jobs, but you also had a lowering of economic activity because you were taking money away from customers that would otherwise have been spent in businesses maybe that weren't green, but were nevertheless jobs in California, so we need to be mindful, and I don't want this to be an environment vs. economy debate, but we need to be smart, not stupid, in how we implement some of the policies that we're trying to effectuate at this Commission and its sister agencies.

I'd like to offer for your consideration four Cost Containment strategies, or principles, first, we need to think through the consequences before hitting the accelerator pedal. I think we've had discussion at some of the prior workshops about the interconnection challenges we're facing, and I think we're moving to get it right, but for goodness case, we're in queue cluster 5, so what happened to queue clusters 1 through 4? You know, we've let a lot of stuff go through the pipeline before really working out the kinks in the process.

Similarly, we're now starting to grapple with the issues of resource flexibility and, of course, it's been at the California Public Utilities Commission that has had to deal with the issue of potential shutdown of Sutter, but it's just an example of getting a little bit ahead of the curve and really having so much RA accounting for renewable resources that is starting to crowd out the very resources that are needed to manage the grid flexibly.

Second principle would be, let's favor competition where possible. We'd like to have markets do the hard work of finding low cost solutions, and encouraging competitive forces to engage in market transformation. Third, let's open competition as widely as possible by encouraging technology neutral rules by designing broad programs and by removing artificial barriers to entry. So one of our panelists earlier today talked about the proliferation of renewables programs, and what that does is it creates the opportunity for people to cherry pick the one that has the best price for them, well, that's not necessarily supportive of competitive market solutions. The panel today in Panel 3 discussed some of the issues of where do we want the renewables to be built -- is it on the rooftops? Is it central station renewable development? What is the most economic choice for the state? And I realize those are difficult choices because, to some degree, at least in our service territory, urban development solves problems that rural development doesn't, but a lot of times the rural development creates significant cost consequences for transmission.

And then finally, let's charge costs to the cost causers, and this is probably the area where this Commission can have the most influence on State policy going forward, and these are critically important things. We've heard a lot about the effect of distorted retail residential rates, and how that can create bad outcomes. Those same principals apply on the wholesale side of the market, as well. And we argued very strongly and, so far, unsuccessfully, in charging the cost of renewable intermittency to the generators who are causing that intermittency, rather than charging them directly to load, which then socializes the cost of the intermittency.

A couple observations that have come up today, Commissioner Peterman talked about improved forecasting, and, yes, improved forecasting is important, it reduces the ancillary services that the CAISO needs to purchase in the market to handle some of the intermittency. But right now, the cost of intermittency are socialized, so it becomes more of a public policy thrust to try to find improved forecasting; if those costs were imposed on the generators, there would be strong commercial pressure to improve forecasts. And the generators would presumably compete to do a better job because there would be money on the bottom line from them doing forecasting. And I think the forces of competition there are going to get it right with a lot greater certainty than us trying to do it in a regulated environment.

Commissioner McAllister mentioned something very interesting about trying to link up demand response with distributed generation, and trying to coordinate so that, if the distributed generation isn't available, the customer drops load. We actually already have a tariff that does that, essentially, that came out of the distributed generation OIR about eight or 10 years ago, and it's called the Physical Assurance Tariff, and the idea is, if you have a distributed generator, and the distributed generator drops, then the customer will get all of their stand-by charges, will be allowed to waive their standby charges if they drop the customers' load when the generator drops, so that they're not putting that load back on the distribution circuit. Now, unfortunately, NEM is essentially a free ride on those distribution costs, so if you have NEM, the customer is getting a per kilowatt hour reduction of the costs of the interconnection, the delivery. And so there's no incentive for a customer to play the game of reducing their load to get costs waived if the costs are already waived, without giving the value of the load drop. So, anyway, that covers my comments. Thank you very much for the opportunity to address you.

COMMISSIONER PETERMAN: Thank you. And thank you for attending so many of our workshops. We'll say it at the end, but you might be interested in our workshop next week on renewables and in-state jobs, and economic benefits, and we want to look at overall economic impacts. So if you're able to listen, or just write your comments afterwards, always appreciate it.

MR. SILSBEE: Thank you for the invitation.

DR. BORENSTEIN: I just wanted to add one thing to what Carl said on the cost of intermittency. I teach at the Haas School of Business, and I have a number of students who are working in trying to start, or working at renewable start-ups, and I recently had a student come to me with the technology that he's working on, on batteries and storage, and he was talking about the valuation of it, and was complaining about exactly what Carl mentioned, which is that the cost of intermittency being socialized actually discourages innovation in storage because his company has a technology that works at Price X, but in order to incentivize renewables, the ISO doesn't impose that cost on the actual generator, and so the generator had no interest in actually adopting something that would help them solve this problem. They're making intermittency too cheap, and therefore making these solutions to the intermittency uneconomic.

COMMISSIONER MCALLISTER: I actually have a question for the utilities. So presumably, then, if it's not on the generator to pay that cost, then the utility, I mean, a lot of this discussion about what's being dropped here and what's not being treated in the structures that we have is, okay, who is going to fit the bill for this, for the grid services that are needed if it's not on any particular -- you know, if it's not on the generator, per se? And if there are not clear signals to the customer that they need to do this either? So what is the utilities' sort of calculus as to, rather than having that storage located at the generator to shore up their intermittency, actually having the utility incorporate it into -- presumably into the rate base, and make the decision sort of system-wide, based on analysis of where storage might go in the utility system, sort of what are the various places where that cost could reside and somehow be recovered?

MR. BRILL: Well, it's kind of similar to the retail issue I mentioned earlier. When we give integration services for free to a generator, they don't care how much integration costs, they'll site wherever it's best for them, and so that maximizes the upward impact on costs and rates for us. It's exactly the same as in the retail setting when you give reliability services for free, that customer would never consider buying a battery. And it's the same thing giving var support, or power quality support, that customer would never consider a Smart Inverter, rather than a dumb Inverter. If we don’t have accurate unbundled price signals, we will not have economic efficiency and we will be spending way too much as a state.

COMMISSIONER MCALLISTER: Okay, so I totally understand that point, and that's kind of why I asked, I guess, so what are the efficiency arguments? Or how can we keep costs down and create the right incentives at the right place? But let's say, you know, you now feel you have to step in SDG&E, or any of the other IOUs have to step in and sort of say, "Okay, we need to install storage, or some other -- or back-up, or whatever," you know, your process for doing that presumably is going to the PUC and saying, "Hey, this now needs to be part of our Investment Plan and we need you to approve upgrades that allow us to recover that cost." Now, is that a realistic path for you? I mean, is that what you've been doing now? Or do you know --

MR. BRILL: Yeah, we put about $54 or $57 million in our CPUC General Rate case for electricity storage for distributed renewable integration and, of course, at FERC, you're talking about policy driven transmission projects for the ISO, and so that's a different regime.

COMMISSIONER MCALLISTER: Okay, so this isn't just a matter of like, "Okay, we need to do this now, we're going to go ask for the money," you actually -- this takes years to get through the process, right? And so -- go ahead.

COMMISSIONER PETERMAN: Most of, I mean, the highlights, we've talked about these issues and some other ones where there are decisions that need to be made very soon, even though we say it, there might not be the need for, say, as much integration in the next couple years in order to get recovery, the rulemaking done, and will take a few years, anyway. Valerie.

MS. WINN: Yeah, Valerie Winn for PG&E. Just on the issue of storage, I mean, PG&E has been looking at really what are the cost-effective ways to integrate more renewables, and storage is one of those, but also adding other operationally flexible resources to the system, you know, is another element that we're looking at. But what we think is really important is developing the marketplace so that they are sending the right signals for the services that those integration measures offer, whether it's if you want fast ramping, that there needs to be a change to the ISO tariff to actually reward those attributes in the marketplace. And without those, you, you know, the things may not develop as quickly as one likes. Whether the utility is going to do some of these things themselves, you know, that's really a big question mark.

PG&E had proposed to look at another pump storage facility and to do some feasibility studies and we were unable to get funding to do that work from the CPUC, so that project has been put on hold. So we have seen a variety of issues developing at the CPUC, and whether they really want the utilities to be in the ownership business of generation and storage, and I think that's a big question mark that we still need to address.

COMMISSIONER PETERMAN: I think that's a good point. I'm interested in seeing how the storage proceeding pans out there. Jim?

MR. TRACY: Yeah, just a slightly different procedure with SMUD having an elected Board, but in our plan, we're looking at much the same alternatives. As I said, we have a pump storage facility that we're looking at. We're looking at testing compressed air storage, and other very flexible natural gas generation. What it comes down to is, you know, and just to put it in perspective, we have about a $3 billion asset base as a utility, and whichever one we choose, it's probably going to be in the range of $400 to $600 million is what we'll have to spend capital-wise to put in one or a combination of those types of facilities, in order to manage the 33 percent that we see coming down the line.

COMMISSIONER PETERMAN: Yeah, as we turn to Severin, I'll just make a plug again for the research programs that the Energy Commission has been engaged in over the last number of years because, I mean, one of the things that PIER has done is to provide grants and funding for looking at storage options, particularly looking at them in different situations, as well as demonstration, because there's no one-size-fits-all model in terms of making those costs go down. I know SMUD has participated in one of those projects, and so I appreciate that, as well as PG&E. Severin.

DR. BORENSTEIN: So I just wanted to throw out a quick historical note, having worked on this since the late '80s, that what the source of this problem -- I think Tom really put his finger on -- which is, as we unbundled more and more, the potential for creating costs for the system that somebody else has to bear becomes greater and greater. And everything we've talked about, whether it's solar PV, or storage, or whatever, these would not be problems -- they're a different set of problems -- under a fully integrated utility because all of that was happening inside the firm, whether it was building new transmission lines to balance the costs of different generators, or worrying about intermittency, if all of those costs are within a system that is centrally controlled by one firm, you don't have that.

Now, there are supposed to be other upsides, and I think there are, to unbundling, and to particularly wholesale competition, but pretending that it's not creating these other spillovers and that we can ignore that because the market will take care of it when there's no market mechanism to take care of it, really doesn't work. And we need to, I think, be more cognizant of all of the spillovers that occur, and the need to price them appropriately.

COMMISSIONER PETERMAN: Thank you. Lynn, anyone on the phones?

MS. GREEN: Yes, for those who have been waiting patiently on the phone, we're now going to open up your lines.

COMMISSIONER PETERMAN: Since we're getting close to the time for your panel responses to be succinct and brief, but of course, well thought out and comprehensive.

[Laughter]

MS. GREEN: All right, your phone lines are open now. It sounds like we don't have any.

COMMISSIONER PETERMAN: Go ahead, Tamara. Hello, Tamara? Nope? Mavis, do you have a comment?

MAVIS: No, I don't have any comments, thank you.

MS. GREEN: All right. Thank you. Is there someone on the phone?

COMMISSIONER PETERMAN: All right. Oh, that's me, it's like a cat chasing -- a dog chasing its tail, if you will, who is on the line, who is on the line? I'm on the line. Okay, any other questions in the room? Do the Panelists -- oh, one more, and then I'll ask if the panelists also have any final questions for each other, or any final comments before we wrap up.

MS. WINN: Actually, not really a comment, but more of a question. Our comments are due one week from today, the day after the long Memorial Day weekend, and I'm wondering if it might be possible to get a few more days for our comments?

COMMISSIONER PETERMAN: Let's give you another week for them.

MS. WINN: Thank you very much. I very much appreciate that.

COMMISSIONER PETERMAN: I don't get to make many decisions unilaterally, I'm looking at staff to see if that's allowed. But why not?

[Laughter]

Thanks. Enjoy your long weekend. Anything from our panelists on the phone?

MS. GREEN: Stephanie or Russell, if you have any last minute or --

COMMISSIONER PETERMAN: Final comments?

MS. GREEN: -- comments, questions?

MR. GARWACKI: This is Russ Garwacki, just thank you for the opportunity to participate. I think it was worthwhile. Appreciate it.

MS. CHEN: And this is Stephanie. I would just echo what Russ said, I think it was a great conversation and thanks for the opportunity to chime in.

COMMISSIONER PETERMAN: Thanks. I'm glad you both found it worthwhile because, Stephanie, as you pointed out, we're making policy for people outside of this room, but we are the ones making the policy, nonetheless. And so I'm glad -- I find these workshops incredibly valuable just in terms of getting different people together, getting this conversation going, having information on the record. I look forward to all of your comments and the recommendations to follow. I want to thank, in particular, Karen Griffin who was the Moderator for this panel, who was very helpful in terms of structuring the questions and keeping this discussion moving, thank you for your engagement, as well as the staff, and to all the panelists. So if there are no further comments, and I'll pause to see, okay, and also just let me take a moment and thank Commissioner McAllister for joining me on the dais, I know he's had a busy day and I appreciated his questions and his engagement.

So with that, thank you very much. We are adjourned.

(Adjourned at 4:42 P.M.)