BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of,	)	
	)	Docket No. 11-IEP-1N
	)	
Preparation of the 2011 Integrated	)	
Energy Policy Report	)	

Staff Workshop on Technologies to Support Renewable Integration (Energy Storage and Automated Demand Response)

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
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Reported by:
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STAFF (* Via WebEx)

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Laurie ten Hope, Deputy Director, R&D Division (CEC)

ALSO PRESENT

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Dave Hawkins, KEMA, Inc.
John Minnicucci, Southern California Edison
Doug Divine. Eagle Crest Energy
Frank Ramirez, ICE Energy
Janice Lin, California Energy Storage Alliance
Charlie Vartanian, A123 Systems
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P R O C E E D I N G S

NOVEMBER 16, 2010 9:04 A.M.

MR. GRAVELY: Good morning, everyone. Mike Gravely from the R&D Division, Public Interest Energy Research Program. Actually, Laurie, don't sit down, I want to introduce you first. So, I would like to start off this workshop by welcoming everybody here to the Commission. This is an Integrated Energy Policy Staff Workshop. I will talk a little bit more about the logistics of that. I would like to introduce our Deputy Director, Laurie ten Hope, to make a few opening comments and just put today's workshop in perspective. Laurie.

MS. TEN HOPE: Good morning. And thank you all for coming this morning. As Mike said, I am just going to provide some opening remarks and context for the workshop that we are going to have today. As Mike said, I'm Laurie ten Hope, I am the new Deputy Director for the R&D Division here at the Energy Commission. This is an important workshop for us and very timely. We're here to talk about Energy Storage and Automated Demand Response and the role it can play in integrating renewables into the distribution and transmission grid. As I'm sure all of you know, California's policy is solidly committed to renewables. We've had an RPS goal for several years and recently the 33 percent RPS has been incorporated into regulations at the California Air Resources Board. The California Energy Commission this year has sited eight large solar thermal power plants for 35 megawatts of renewable central station renewables, which is, if all built, somewhere around 10-15 percent of that goal. Our Governor-Elect Jerry Brown has, in his clean energy plan, called for an additional 20,000 megawatts of renewable, 12,000 megawatts of which are on the distribution system, so we have been thinking really about the integration of storage at the end use and at the large utility scale, but his plan, if it goes forward as articulated at this point, really calls for a community scale look, as well, which is a fair amount of renewable generation on the distribution system, which creates new challenges and opportunities for those of us in the research area.

So, this workshop really is going to lay out some of the challenges and the research opportunities for storage, demand response, and other tools to manage the cost of integrating renewables, while maintaining the reliability of the grid system. This workshop is an outgrowth of the 2009 Integrated Energy Policy Report; the Policy Report sort of laid out what some of the needs and opportunities were for storage to perhaps address integration, first identifying some of the needs, and I'm just going to read you a couple of quotes from the 2009 IEPR. The first, "Significant energy storage will be required to integrate future levels of renewables, thus allowing better matching of renewable generation and electricity needs. These technologies can also reduce the number of nature gas-fired power plants that would otherwise be needed to provide the characteristics of the system needs to operate reliably." That statement right there underlines the Skinner Bill, AB 2514, that perhaps storage could mitigate the use of natural gas as a load leveling strategy. "However, many storage technologies are still in the research and development stage, are relatively expensive, and need further refinement and demonstration." And, you know, that is part of what we want to explore today. What is the potential? What are the research opportunities to lower the cost and really take this from what we sometimes call the "Band of Miracles" if we are going to get to our GHG goals and our renewable integration goals. We have a lot of tools in our toolbox, but some of the tools are still quite expensive, or really need some technology breakthroughs to realize the potential that we hope for.

A couple other points of context. As I mentioned, AB 2514, the Skinner Bill, raises the bar on energy storage, it requires the CPUC to look at regulatory strategies to incorporate storage, and we hope that this workshop and other work in the PIER Program will assist the Public Utilities Commission in its responsibilities under 2514.

Today's workshop will address the current state of energy storage technology and discuss the many emerging technology demonstrations that are being funded through DOE's ARRA Smart Grid funding. Under Mike Gravely's leadership, the Energy Commission really went after Stimulus funds in a big way and partnered with many of you and other stakeholders in California to try to bring Stimulus funds, both in the Smart Grid area and the storage area to California. One unique aspect of this workshop is the inclusion of automated demand response as a possible resource to support renewable integration. So, we want to look at the opportunities that DR can play, and maybe couple with storage, maybe the whole is greater than the sum of the parts in terms of the niches that each of these strategies can play.

Today's workshop will help us define the efforts needed over the next six months as the Commission staff works with the ISO, utilities, industry, and researchers and other key stakeholders, to determine what actions are possible to accelerate the ability of energy storage and demand response technologies to help California meet the integration challenges that the Renewable Portfolio Standard provides. I want to welcome all the presenters that are here, all the other stakeholders that are here in the room, and those of you on the phone participating by WebEx. And I am now going to introduce Mike Gravely, who will take us through the rest of the day. Mike is the Office Manager for Energy Systems Integration and architect for much of the Smart Grid and storage research here at the Commission. So, Mike.

MR. GRAVELY: Thank you, Laurie. And I'll take just a second here for a couple of administrative items. There are about 50-60 people here in the room, so if we get a fire alarm or anything, we would go out across the street to the open park over there. The restrooms are right across the corner. There is lunch planned and an afternoon break, but not really a morning break, we'll see how that goes. We have a pretty full agenda, so feel free to take a break if you need during the session here. Also, I'd like to take one second here and have our Administrative – would you un-mute – I just want to be sure, will someone online simply confirm that they can hear okay, and we're transmitting – I want to be sure that the people on the WebEx are able to hear and see the presentation. I will stand a little closer to the mic here. And we will have people in the room go to the mic; because this is also being recorded for purposes of our notes and the for the IEPR presentation, those that come in the room and want to speak, please go to the mic and give your comment or question at that time, and we'll do our best, to be sure. If you have a problem typing your comments or whatever, we do have help here monitoring the WebEx and they will be able to read your comments. There probably will not be an open discussion session, and we'll try and have one just before lunch for a few minutes, so if you have questions that are coming up, I would encourage you to type those in and they will be passed over to the presenter and see if they can answer them. We probably won't have a lot of open discussion in the morning, we have over an hour in the afternoon for questions and answers to cover things from there.

So what I would like to do now is just kind of explain this workshop and what we plan for today, and what we have planned for the next six months to a year in this area. The overall purpose, this is part of our Integrated Energy Policy Report preparation for 2011. The report will actually be drafted in the fall and made out for public comment, and it will be published before the end of the year. We do these every year, this is what we call the on-cycle – we have a two-year cycle for the report, 2009 was the last one that we had a full report, in 2010, we had an abbreviated report, so 2011 will be a full report, and 2011 is going to spend a considerable amount of time on infrastructure, so obviously storage and renewable integration is part of infrastructure, so this is core to providing the data. The other thing important in this workshop here is that we need to have the information that we use docketed and part of the workshops, the public workshops, so the presentations you see today may be longer than the individual will actually be able to present, but the important thing is to have the data into our record, the information available, so if all the charts are not covered, don't feel bad, the purpose of that is to ensure that we get the information into the record and we're able to use that information as we prepare inserts or sections for the upcoming 2011 IEPR.

This is a two-phased workshop. Today's workshop is going to focus on technology, and the ultimate question is what is the state of technology now; one of the statements in the 2009 IEPR was that the technology needed to evolve and that there are some technologies that are mature, and some technologies that are still developmental. So, we want to try to put together kind of an assessment of where we are as part of this work over the next six months. Also, most of you know and you will hear today several presentations under the American Recovery and Reinvestment Act, there are a substantial number of storage projects, we are fortunate that many of those are in California, and so that funding is going to accelerate some of these technologies that may have taken three to five years to mature, maturing one to two years from that area. And also, we are looking today at integrating automated demand response and I will talk a little bit more about that as we go forward, as a grid service, as opposed to demand response as a peak load reduction service. So we are going to talk about it today simply in the mode of, can Auto-DR provide a similar service to storage with a similar envelope. And I'll show you those as we go forward.

And then there are substantial barriers and obstacles and challenges that we want to understand, so today I'd like to simply identify those if we have the opportunity. Certainly, I encourage everybody online and all the participants here to follow-up this workshop with more formal comments, more formal information, or more detailed information. This is one area where I'm soliciting all the vendors online and here to give us your marketing and sales information so we know what your technology can do, and what you say it can do, and it will help us understand what is evolving in the marketplace. Again, for this particular workshop, we're focusing primarily on grid-connected large scale storage. I'll talk a little bit later about what we're doing in other areas of storage, but for this workshop and for this area, we want to look at supporting the RPS. But that doesn't mean – large scale does not mean aggregation of distributed resources because we will have a discussion today of a very large distributed resource, actually, that is providing multi megawatts of service to the Grid.

And so we are planning a workshop in the April timeframe, the date hasn’t been picked yet, but we’ll probably post it after the first of the year, and then, in that workshop, we will briefly summarize what we’ve learned on the state of technology, but we’ll focus most of that workshop on what type of obstacles and barriers exist, what types of policies and recommendations, can we address those, and then what needs to happen so that storage can play a major role as we think it should in the 2020 environment, and what does it take to get there.

Also, I’ll point out, for those that are familiar with the Public Energy Research Program here under the R&D Division, we have a long history in storage, we have hosted multiple awards, we manage contracts, field demonstrations, we share those publicly. Many of our demonstrations that we’ve had in the past have gone on to some higher level of commercial success. We encourage partnering. We’ve done projects where we integrate renewable storage and community scale projects, too. So, we are looking at different opportunities. And one of the things we’ve been doing, there are several members here in the Commission, myself and

Promode Kulkarni are two of them, they are kind of the missionaries for storage. We have been preaching that storage is something we need for a long time. I have discussed many years ago that, for California to reach their 2020 goals, we need thousands of megawatts of storage on the Grid that we don’t have today. And fortunately, you will hear a report from KEMA later today where we actually were able to quantify that, and they also agreed, and ISO agrees, that we need thousands of megawatts. How many we need and what scale we need is still to be determined, short, medium or long term storage. But I think people realize, if we’re going to do a third of our generation with renewables, that we need substantially more storage, and then one of our challenges is to figure out how to meet that need the most effectively, and particularly the most cost-effectively.

The other area we’ll talk about today, we’ll spend probably two-thirds of the session on storage, and a third of the session on Auto Demand Response, and we have a long history in Auto Demand Response in the PIER Program, we actually formed the Demand Response Research Center about eight years ago. We have been supporting demand response research and the automation of demand response, in fact, that automation has matured to an open ADR protocol as part of the Smart Grid standards that are being negotiated right now and because of that maturity, we think that technology is ripe for this new opportunity, which really hasn't been considered for a long time.

Here is just a collage of storage projects, we'll hear many different types today, we'll hear about compressed air, we'll hear about pumped hydro, we'll hear about batteries and other systems out there today from different technologies. We're not able to present every technology, there is an open session and what we do allow, if someone wants to present their technology or a project, you have up to five minutes, I need you to make an arrangement by e-mailing our WebEx and let her know that you want to speak, or bring a blue card up here and, at the time of public comment, we'll allow you to give a presentation, and we can also upload a Powerpoint if you choose to do that. We will stay here and take comments, there is an hour and 20 minutes or so proposed for comments, but we'll take comments as long as people want to talk, so there is an opportunity for people that are not on the agenda that want to present something that they consider of substance. We will welcome that. Those of you that just want to send that in for us to evaluate, or if you want to set a meeting up with us later, Avtar Bining, who has been setting this up, is our Energy Storage Manager, so he will be the contact if you want to set something up with the Commission, work with him and he'll arrange for you to come in over the next six months and talk to us.

This chart here is the best I've seen and this is a DOE chart that just shows you graphically the difference in, we'll say today, this is renewable wind, primarily, but you can see, if you go to 35 percent, which is pretty close to 33 percent, you can see the disruptions that it has on generation in the system that don't like to operate that way, so we have to find technologies to make upper lift for some of those systems to continue to operate that way while we handle the disruptions that occur because of the renewables. The other chart that people see a lot is this one, this is for actually California, it just shows you that, you know, the average looks really nice, but the day-to-day and the hour-to-hour projection doesn't look real nice. And so we understand the ability to get lots of renewables and lots of wind, and as we put more and more on, we'll have more and more of those. So, the challenge, again, for us is how do we use different technologies, and storage and DR are two of those that can help us do this. We want to make it work, and we want to make it work as effectively as it does today, and as reliably as it does today.

Solar, it does work when the sun is up, but it has its own challenge, in California the sun comes up and it gets hot pretty fast, and you can see that what happens is the solar ramps up very fast, so we have a very large ramp in the morning and a very large downturn in the evening, and so there's a lot of transfer there and you need energy protection to help that work for a small window, and so we would prefer to have technologies that are available and inexpensive, than having to have generation sitting there for, you know, an hour in the morning and an hour in the evening.

These technologies here, just a collage of the different technologies and we will discuss over two-thirds of those today, but not all of those, but we are looking at all the different types. As I said before, today we'll be focusing on large utility scale storage, but in the PIER Program and in some of the research we're doing, we're focusing on all storage.

There is a project that I want to point out, this project is being managed by Avtar, it has been approved by our R&D Committee, it is going through the process now of negotiating and finalizing the contract, it will go to our business meeting, we hope, before Christmas, if not, in early January. It is about a six-month effort, and we are trying to put together a vision for energy storage for California. And so we will actually be looking at that information. In this case, we'll be looking at not just Grid storage, but all storage in this area, so we will be looking at where storage should be and what happens, and we're hoping the results of this information will be provided to the PUC and also to other individuals, and so we will do this interactively with industry, but the ultimate goal here is to understand as we reach our goals of the RPS and other greenhouse gas reduction goals, and Grid management goals of 2020, how can storage play a role, and what storage is cost-effective, and in what application.

Just to talk briefly about demand response, this shows here that we have focused a lot of our attention on automation of demand response. The lower left shows you that we have a lot of success. You'll hear more this afternoon from Mary Ann Peitte and other individuals that will represent this. We have already done research for many years on use and demand response as an ancillary service, but primarily at a small scale, and we think, now, with the integration of automation, if we're able to look at the broader scale automation, then we can do this rather than being hundreds of megawatts or tens of megawatts, it can be thousands of megawatts, that's our ultimate goal because cost-affectivity wise, we believe that the DR will be the most cost-effective service, and then we have to go from there to the storage. But DR cannot do it on its own, it only has a certain piece it can play, but we want to use it as much as possible.

And so, what happened here, this shows you the classic Auto-DR, and that is that we looked at, you know, the morning time and the peak time, and this just gives you an idea of what a classical DR can provide and service. What I've been trying to do now, and what I have challenged the Demand Response Research Center for about six months ago was to look at DR as a service and to define it the same way we define storage; in other words, it takes so long to come up and run, it'll run for so long and then it drops off. So, give me that envelope and, based on that, I've asked them to take this and say, okay, what will Auto-DR do? And you help me, we think it can respond in 40 to 50 seconds, and we believe in the future that might be 10-15 seconds we can get a response time, we think we can get 20, 30, 40, 50 minutes pretty consistently, it could be hours. Our research we've done to date shows that a customer, if we have a 30-minute activity with an air-conditioning unit and it's on and off in 30 minutes, the customer doesn't really know what ever happened, and the Grid gets a response. So, we could actually use Auto-DR and a Grid service much more actively than we do right now, just on peak demand where we want to do it 10 or 12 days a year, we could literally use this every day and the customers would benefit for that, and the Grid would benefit for it, and the cost-affectivity would be substantially less than having to put in a dedicated system.

Just as we mentioned before, we are fortunate, California did receive a very large amount of ARRA projects. In total, we got over almost $500 million, this is just the Smart Grid part of it; if you add it altogether, we have about $1.2 billion in Smart Grid related projects and those include storage projects, and those include Auto-DR projects. So, today's workshop, you know, we will advance technology, the cost of the ARRA investment, there is no question about it from there.

So, what I'd like to do now is just take one second and go over the agenda. Let's see if I can get this to work right. So, the agenda has changed just a little bit, but the agenda is online, and for those of you online, you will be able to see the presentations as we present it, but we are posting those and they should be posted, if not by lunch time today, but the end of the day. So, all the presentations you see today will be posted and they are publicly available. If anything happens and you can't get them, feel free to e-mail myself or Avtar, and we'll be glad to e-mail them to you. The problem with e-mail, of course, some of these are very large and you can download them from the Internet, but you can't always e-mail them.

So we're going to have just a few seconds here, the PUC may be online and I think if Chris is online, he wanted to make a few comments, and I'm going to let him do that, and then we'll go into the discussions that we have here. So we'll start off hearing from the ISO, and then we'll talk about the Storage I've talked about that KEMA did for both the ISO and the Energy Commission. And then we're going to go through hearing from a different technologies and different users throughout the day. We have a pretty broad perspective, we're seeing everything from very large storage to small distributive storage, and we tried to capture as much as possible, all the major players and major technologies that are out there. Again, I realize we can't capture everything, but I also, again, will just keep reiterating all day today, please provide me information through the docket if you have information, you know, everything is on the announcement where to send it, and then we have that information available, so we're hoping to provide a presentation to our Commissioners on the state of technology as we go through this, and help them understand that is possible as we go to the future. So, is Chris Villareal on? Or, if Andy Campbell is on, they mentioned they may want to talk for a few seconds. So, hello, is Chris or Andy Campbell, either one on? At one time, they were going to make a few comments. If not, later in the day, I'll be glad to because they are setting up to execute the AB 2514 and, of course, they're doing the Smart Grid

Deployment Plans also. Is anybody from the PUC on that wants to speak? Okay, we'll check with them later and maybe after lunch we can give them an opportunity to speak.

And with that, I'd like to turn it over to the ISO. Let me get your presentation here for you. Okay, he will load it real quick. So, I'll let you go ahead and introduce yourself here and we'll go from there.

MR. HELMAN: Thank you for the invitation to the ISO to kick this off. My name is Udi Helman, I am a principal in the Market and Infrastructure Division and I'll be giving an overview of some of the work that we're doing on renewable integration and some of the implications for storage and demand response. I wanted to say I also have John Goodin, our lead expert on Demand Response with me, so he'll be available for any specific questions on Demand Response initiatives.

Okay, we have a lot of efforts and initiatives addressing renewable integration and demand response and storage, and we obviously don't have time to list all of them, and I'm not going to try to, but this schematic gives you a sense of the core functional areas in which these efforts are advancing, and that includes our system operations, the design of our wholesale markets, our grid planning, and our support for the state's Resource adequacy Program. The arrows that I have in this chart are just indicating that, as new technologies come on board, and as renewable integration studies advance, all these functions become more and more integrated. I think, as all of you know, the ISO last year implemented a new market design and that's a market in which market price signals are much more heavily a function of constraints on the system than they were in the past, so we have a day ahead hourly market and a real time five-minute dispatch market, all of which and both of which prices are calculated on the basis of a full network model that includes all unit operational constraints in it, as well as transmission constraints. So, we have a market now that is much more suited for the integration of demand response and storage, as well as renewables. And we envision, of course, that those market prices will be a major piece of the control of both automated and dispatchable resources in the future. At the same time, we have evolving visions for some of the specific technologies that are being discussed today, including demand response and the Smart Grid. Again, I won't be talking about those here, but look to our website for more information over the next few weeks and months.

We also have some large storage in our generation interconnection queue, again, I won't be talking about that, but the revisions to our Grid planning process that we submitted to FERC a few months ago specifically talked about the integration of renewables and the integration of resources to facilitate renewable integration, so we have as part of our mandate to do a better job of understanding the impact of both storage and demand response on Grid planning going forward. So, there's a lot going on. I know it's hard to keep track of everything that is going on at the ISO and there are some central points on our website for our different functional activities, but we can try to continue to do a better job of ensuring that people can get there and understand exactly what's going on with respect to storage and demand response as we go forward.

Some of our objectives and principles, as we continue, one, a really important thing from our point of view, are to understand the multi-year operational and market context to inform technology and infrastructure investment decisions. So, that's a piece of the analysis that has been hard to do in the past, given all the potential scenarios for the future, but it seems to be settling down this past year, a lot of work was done, and this coming year, I think even more work will be done, that will clarify the needs in the future. But, in the mean time, I'll be talking about two studies that are ongoing that we're doing that look out a few years and then sort of two to three years, then out to 2020, and you know, we need to keep clarifying the conditions on the system as they go year by year, so we know the key junctures when new technologies and new capabilities are going to be critical to system operations. At the same time, we're also working to reduce barriers to demand response and storage, mainly the small scale storage, large scale can already operate fairly easily in our markets, and we're thinking about any new market products that are needed specifically to cover new capabilities on the system. So, we have a number of efforts in that area.

It is important to understand that one of our principles at the ISO is that we're technology neutral, we're not going to be in the business of picking particular technologies to meet these needs in the future, we're looking to policy and market price signals to guide those decisions. I'm getting a little closer to the mic. So, we try as best we can to remain technology neutral and to provide the information on the combined operations of the system using both conventional resources and new technologies, so that decisions are as informed as they can be as to where investments should be. So, we're technology neutral, but we're also dedicated to ensuring that any new technology can operate on our systems. And then, finally, on this slide I should mention that one of the frustrating things, I think, for entities trying to advance new technologies is that we have to prioritize changes in our

ISO market and systems operations year by year, so while we do our best to keep the ball rolling forward, we have a backlog of changes that need to be made that are already mandated by FERC, and so we're trying to get as many new capabilities in the mix and lined up to be ready in time as we can. We think that a lot of our initial backlog in terms of our markets will be done in the next year or so, and we are working hard to get the new capabilities needed to integrate storage and demand response ready to go over the next couple of years, so things will speed up even if they've been taking some time to get to this point.

So, with that sort of very general background, I'm now going to show some of our initial study results and talk a little bit about those, and what we can learn from those, and also to get into the state agency processes thinking about how to improve the analyses that we do as we go forward. So, the first of these studies was the study of integration at 20 percent of RPS, and this study was published just a couple months ago. It's the first attempt, we think, to do both wind and solar resources at 20 percent RPS in a detailed fashion, and the study, a draft technical appendix, and stakeholder comments are available on our website, and I encourage people to go and look at that. Even though the objective of this workshop is 33 percent RPS, there is a lot of information in that study that is relevant to the system many years ahead, including some inventories of our existing system capabilities that are important to understand as we move forward. So I won't be talking about too many of the results in this study, I will be focusing a little bit more on our 33 percent simulations, but it is still relevant to go back and look at it even as we are thinking about 2020. And I will show some of the types of results that I'm talking about.

Then, perhaps of more relevance to the discussion here is our first run at doing 33 percent operational and market simulations. All the information that we have so far is available on the PUC website because we structured this study in part to support the PUC's Long Term Procurement Planning proceedings. So, we have been channeling those results through the PUC workshops and will continue to do so into the near future, although, as we continue to articulate, our analysis, we are doing it as if with our own objectives in mind, as well, we're not simply there to provide information to the PUC, we have to do our own preparations on our ends, and so how we go about these studies is informed as much by our own objectives as it is by their objectives. And we also emphasize fairly consistently that, as was pointed out by Mike, there are a lot of uncertainties about future technologies, future conditions that have to be taken into account when we look at results 10 years out. We are going to produce another round of simulation results on November 30th and that will be at another PUC workshop in this process, so that will add another set of possible future needs and outcomes to the discussion. And I think some of you will be pretty interested by what those results are. But I can't show them here, sorry.

I guess Mike already showed what the world looks like in 2020. These are individual days that we're modeling in our simulations, so this is a [quote] "high wind" March 16th day in 2020, so you see the wind – and these are profiles built up from a one-minute basis, based on analyses that we prepared, so I will not go into great detail into the methodologies, but we are doing analysis on the one-minute, five-minute, one-hour sort of timeframes in our simulations, so you can see some of the variability that builds out from a one-minute basis in this graph. What's important from a storage point of view is, you know, what role is storage going to play, and I think there will be some counterintuitive results coming out of these studies. I know that our 20 percent study already showed some interesting results, there is a slide that I will talk to about those. But we can see obviously that storage and Demand Response have a role to play in variability, and that was already discussed. But the value proposition will also come out of what prices will be telling us, and I think what is very interesting about 2020 and even about two to three years out is the immense displacement of gas by renewables, affecting energy prices, and we showed some of that in our 2020 percent report already, showing a big drop in, well, not as big a drop in energy prices, but a big drop in energy revenues for gas plants. And this purple line in this graph is the net load, that is the load minus the wind plus solar, and it is this pushing down across the entire day that you have on days like this, that pushes the energy prices down both in the off-peak and the on-peak. The expectation used to be that you'd get a big gap opening up between off peak and peak, but with the inclusion of all this solar in the current forecasts, you get a suppression of energy prices both in the off-peak and the peak, so the value of energy arbitrage may be less dramatic than one hopes by 2020, and that will also be a function, of course, of whether this carbon pricing to push up the on-peak prices, as well. So there are a lot of variables in understanding what the real value proposition will be for storage and demand response. The other interesting thing is that peakers in our models are no longer really peaking resources, they're variability resources because of this solar influx that knocks out, you know, gas off the peak. So, just in our 20 percent study, we showed a huge shifting in the revenues to using an hourly model, and there are a lot of caveats here that have to be explained, but the less efficient gas plants are obviously pushed out of the peak. But then they retain some value in providing support for variability within the hour that we have to understand better. And then, another profile, as you know, the variability will be dramatic and so this is a low wind summer peak day, and here we see that the solar is doing most of the work in displacing gas across the day. And so the impact across seasons, across different days on prices, will be extremely variable and there is a lot of work to understand that.

Our general sort of results from these renewable integration studies of interest to storage and demand response is significant increases in the intra-hourly load-following, and its generic terms is load-following, but it's really load-following and variable renewable-following requirements, and as the two graphs I showed just now, these will vary by season and by hour, so there will be hours of the day in which there will be a very high need for resources that can follow variable renewables and there will be hours of the day in which there isn't as great a need, and that will vary by season. But there's no question in the analyses that we're doing that we see significant increases, and one of the things that is helpful about our work is that we're helping to clarify and quantify some of that. And similarly, we show significant increases in regulation requirements, also varying by season and by hour. As I discussed earlier, the energy market prices are expected to decline as renewable energy displaces gas across the day, and that is the combination of wind and solar, however, real time prices will be expected to become a lot more volatile as the intra-hourly market provides that load-following function, and so there is a lot of potential there for storage resources. And then, ancillary services markets, obviously we'll be procuring more ancillary services, but what the impact on prices will be, will be a function of a number of factors, including what other resources are on the Grid, including the gas plants that are displaced out of energy, but a lot of which are still committed and will be available to provide ancillary services. So, these are really complex modeling issues and we're making progress, but they do affect the sense of how much storage and demand response would be needed.

So here are some of our attempts to quantify these changes on the system, this first slide is load-following up by hour in the summer season, using the PUC's 2009 33 percent reference case, that was a case built out on the basis of existing contracts largely, and has about, I think, 10 megawatts of solar in it, with the remainder being wind. And this shows you that – this is essentially telling you that, within the hour, we'll need – the blue graphs, the blue plots are a benchmark year, we try to have a benchmark year in each of our analyses that we can measure the change in the system. This benchmark happens to be 2005. And then the red is the target year in 2020 and we can see that we need about a thousand or more megawatts of basically upward capability available within the hour, typically. So that's what that is showing you. In some hours, more than a thousand, closer to 1,500 megawatts more, on average, than we have now. Let me just say that one of the other improvements that we did in these studies over some of the prior studies was we tried to give a sense of the range of possible results that will happen over the year, beginning from some baseline profile of renewables, so that, you know, past studies have often shown you the maximum requirements on the system, and one of the questions was, well, how often does that happen? And we've really tried to go a long way to explaining how often that would happen in these more recent studies. So, both in these kinds of plots and in frequency distribution plots that are both in the slides and in the studies, you get a sense of, well, yes, here is an example of where the simulation, if we look at essentially Hour 7, shows you almost 5,000 megawatts of load-following needed on the system, up from the simulated 3,500, but that is only happening for an hour, so in the simulation of 87/60 hours. So, getting that sense across has been important and we have an ongoing discussion about refining this modeling, but I think everyone has appreciated that we're providing this further type of information as we go forward. And similarly, these are plots of that same scenario for regulation in 2020 and, again, you have heard that we need over 1,000 megawatts of regulation, you've heard that in the past, but these simulations results help show you that, well, that may only happen in a particular hour of the day and, for the rest of the hours, we may not need more than between 400 and 600 megawatts of regulation. And then, there are further caveats, like what if the renewable resources become more dispatchable? For example, as we go to the next slide, in the instance of providing regulation down, what if the renewables become more dispatchable in certain hours to reduce overall system costs, they would further cut off some of these requirements. So, there are a lot of moving parts. Forecast errors – if we reduce forecast errors further, we will reduce the estimates of these requirements on the system. So, these are all considerations as we go forward to help clarify and there is a lot of discussion of this in our studies.

Another important piece of information that we have started to put out, and again, this was in the 20 percent report, is inventories of what capabilities we have on the system now, and so we have a number of tables in the study and we'll be providing those, more of them, in the future, that inventory, our generator fleet, by operational characteristic and by unit type, and that includes ramp rates, how much capacity we have that can provide particular ramp rates, start-up times, and regulation, certified ranges, and ramp rates. And I'll show you one of those tables in a second. And then we also classify them by unit type, so OTC vs. non-OTC units, for example. And I'll also show you, in the 2020 analysis, we're looking at different future fleet mixes, so looking at potential future fleet mixes and what capabilities we'd have on the system, and those scenarios. And that's where, as I'll describe, we haven't yet gotten to including large scale storage as part of that future fleet mix. But it's useful to benchmark it with conventional gas plants, and then we can move to understanding storage on a large scale – better. So, this is an example of – this next slide is the inventory of our current fleet, and one of the things that we did in the 20 percent report was try to explain better to the market, especially the storage market, the smaller storage, in particular, you know, what potential is there for providing regulation in the future. That's considering what is already on the system. And I think what may have been surprising to some people is that there is a lot of regulation certified capacity on the system; at the bottom right-hand point of this table, you see there is almost 20,000 megawatts of regulation certified capacity across the different types of units that are already on the system. And then, our simulations, both on the 20 percent study and the 33 percent study, have tried to carry the additional regulation requirement as part of the production simulation in the future, to see if we can create a unit commitment dispatch that provides the additional regulation needed, as well. And so, what this is telling us is that – and there are some other analysis in the study, as well – is that, yes, we will need to buy more regulation, but there is a lot of existing capability to provide that regulation and we can generally commit the units to provide that capability with our existing fleet. So, what that is telling you is that the value of regulation will take time to show up, even as we get additional renewables on the system over the next, you know, on an increasing basis over the coming years.

This is just a piece of information that I think has been important to get across, it's just objective information. So, this table is one of these look-ahead's to 33 percent and what this is telling us is that – and what I just said, you might consider to be an issue for the valuation for storage over the next few years – but as we look out 10 years, one of the things that we're starting to catalogue and model is the impact of the additional renewables as they qualify as resource adequacy resources given the current rules. They displace conventional resources from resource adequacy, credits -- essentially capacity credits. So, if we build out a system that meets the planning reserve margin, the remaining resources, what this chart is showing you, and obviously it is hard to see, but there is another graph coming up, the remaining resources have less and less flexibility on them because there are fewer and fewer gas plants that are eligible to be resource adequacy resources, and energy market revenues are declining. So, there is going to be a lot of cost pressures on them and the remaining ones will be – have less and less flexibility. And that is what this chart is showing you, it's showing you that these are across the columns, the first one is an all gas benchmark column, so that is as if we included only additional gas between now and 2020, and then there is incrementally higher and higher renewable scenarios. So, the next column is 20 percent RPS in 2020, and then a 27.5 RPS in 2020, and then a 33 percent RPS using the portfolio that I discussed earlier, and then various other scenarios like the high DG scenario, and the high out-of-state scenario. And this green column, green row, is percent reduction from the all gas case, so we see that, by 2020, there is 16 percent less regulating ranges, eligible regulating ranges on the gas fleet than there is in the all gas scenario; and similarly 20 percent less ability to provide load-following. So, this chart, in comparison to the last chart, I think, is a good news chart for storage and Demand Response because this is saying that system requirements – the flexible resources, the ones that are able to follow dispatch, will become a narrower and narrower band of the system. And that's where the opportunities lie for newer technologies.

In this next graph, and I should just also mention that these two graphs I've shown, these are not simulation results, these are inputs into a simulation, so these are just – this prior slide 14, this table, these are just the power systems that we are modeling in the simulation, and these measurements I've done about capabilities are just looking at the ratings of the plants that we're modeling, and fatting them up, essentially. So, this is going into the simulation and the results coming out of the simulation will be available at that PUC workshop that's coming up at the end of the month.

And this graph is a version of – this shows on the blue line that the sum of the regulation load-following requirements goes up as we go from the all gas in 2020 case to the 33 percent case, and the red line is showing you that the capabilities, the sum of the capabilities on the system is going down, so that's just another illustration of what I was just describing.

So, where do we stand and what do we plan to do next? The 33 percent simulations, as I said, additional results, I should say, a bunch of results are already out there; additional results will be available at the end of the month, but then we're getting a batch of updated PUC scenarios, and so we're going to have to re-run everything again another time over the next few months. So, our focus has been on methodology so far, we wanted to get the modeling in a reasonable shape, in a way that people generally agree that the results are meaningful, but then we're going to do some updates over the next few months, so, you know, obviously all of this will be updated continuously, but we will do some – it's worth looking at the results and understanding what they're telling us, and then, you know, we will be continuing to analyze it.

One of the weaknesses of the analysis, so far, of the 2020 case is that the production models, the ones that are modeling the entire system, hour by hour, have not yet drilled down on an intra-hourly basis. We have intra-hourly requirements that are calculated through a statistical model, and I showed some of those results earlier, but the production model isn't fully capturing some of the incremental and decremental ramps within the hour, and we want to do some further work on that and that will provide, I think, more insight into the capabilities of faster ramping resources. So far, we have in the models, if you go and look at them, we've held sort of capacity in reserve to account for those upward and downward requirements within the hour. So, there is more sophistication coming, and of a type that will be useful, I think, for storage and Demand Response. Of course, every time we have a meeting, we get the police from the storage community to do more analysis of storage in these simulations, and it is in our plan, it's hard to model storage in some of these modeling frameworks, but that is the next step on our agenda and that will be announcements that will happen in this coming year. So, be patient, but the results that you see so far are still useful results, and even in thinking about storage needs and storage capability. So, you know, we will do more as we go forward this coming year.

And then, finally, I just want to say that, on the market side, we are proceeding to speed up our abilities to introduce limited energy storage into our markets, so there is an initiative this year and the coming year to introduce a method called regulation energy management for those types of resources. So, a lot going on, and I'll be here in the morning to answer questions, but I won't be here in the afternoon.

MR. GRAVELY: Okay, thank you very much.

MR. HELMAN: Thank you.

MR. GRAVELY: Okay, the next presentation is by David Hawkins here, but just before Dave, the PUC is online here, so we're going to wait and maybe have questions at the end since a lot of the ISO type of information is in the report, we're going to hear from now. I would like to go ahead and have you open up the line. Chris Villareal from the PUC, who has been working with us and our partner on this effort, and is managing the Smart Grid effort, the rulemaking, and also actively involved as they are preparing for the AB 2514 work. Chris, are you on?

MR. VILLAREAL: Good morning, can you hear me?

MR. GRAVELY: Could you speak up a little? We hear you, but you're weak.

MR. VILLAREAL: All right, can you hear me? So, good morning, everyone. Thank you, Mike, for letting me –

MR. GRAVELY: Hang on one second, Chris. We're going to try and change your volume a little bit here. Try it now, go ahead.

MR. VILLAREAL: Okay, hi, Mike. Can you hear me?

MR. GRAVELY: That's much better.

MR. VILLAREAL: Okay. Good morning. I want to thank Mike and the CEC for letting the PUC have a couple of minutes to give our view point on Storage. The PUC obviously has a very strong interest in supporting storage as we view it as a critical technology to help meet our 20 percent and our future 33 percent goal of intermittent and renewable resources. Additionally, as we start shutting down the once-through cooling facilities and increasing loads through electric vehicles, storage is going to have an even greater role, not only on the transmission side, but also on the distribution side. So, the challenge for the PUC is how do we adequately account for the various revenue streams that are coming from one storage facility when that storage facility can act as a generator and act as transmission support, and can act as supporting distribution.

Recently, Governor Schwarzenegger signed AB 2514, which directs the PUC to open a proceeding by 2012, to address policies, to incentivize storage on this cumulative [ph.] level if we decide to set up storage on this current [ph.] level if we decide to set up care [ph.] with storage target. Again, the issue will be how do we adequately and accurately measure the cost-effectiveness of any storage project. The two clear issues are, which is the right technology, and what is the most economic for customers, not that we want to pick technologies, we'd rather just have it be technology neutral, and let the utilities on the market decide which technologies meet the goals and the needs of

California customers and the system as a whole. So, the proceeding that we plan to open up soon will address how the PUC should best create policies to allow storage to take a greater role in utility infrastructure and operation. I'm with the PUC's Policy and Planning Division, and earlier this year, we issued a White Paper that laid out some initial thoughts and options as to how to move forward. One option, as indicated in AB 2514 is to create a procurements target. There are a number of other options such as creating other incentives through contracting that may be more efficient in getting the right technologies into utility hands. One of the concerns that we've heard regarding the procurement targets is that all it does is incentivize existing storage and not necessarily the cutting edge technologies that we are all so interested in today. I know that Udi said that following storage at the ISO is quite challenging, and I would argue that it is even more challenging at the PUC, as we have currently five different proceedings that all, at one point or another, will address integration of storage. We have an RPS, we have the procurement, we have Demand Response, we have Distributed Generation, and we have Smart Grid. In addition, as storage becomes more robust and is taken into the utility rate cases, we have these rate cases themselves, and we also will have future issues with storage and resource adequacy, as we decide whether or not to give storage – not only whether to give them a capacity value, but what should that capacity value be.

And finally, I just want to point out that the PUC in our Smart Grid phase has so far approved two storage projects that received Stimulus funding, the first one is in PG&E’s service territory, which is a compressed air storage project, the funding we approved is only for Phase I of a three-phase project, Phase I addresses the feasibility study. This project is located in the Central Valley. I can’t quite remember where in the Central Valley, but if there is a representative from PG&E there and it comes around, he can address it. And the second project we’ve approved is, I believe, a four megawatt or an eight megawatt battery storage facility located at the Tehachapi site on Edison’s transmission site. Both of these projects have been approved by the PUC and, to my knowledge, are still awaiting funding from DOE.

So, all I have to say is that the PUC expects storage to take a greater role and we expect to create policies in the near future to allow utilities and to create a market for storage where appropriate as we move forward in this brave new world of increasing renewables and EVs and more distributed side generation and storage. And we view storage as just being one of the – to use a phrase I actually don’t like using – to be a “killer app” in this brave new world of the electricity Grid going forward. And that’s all I have to say, thank you.

MR. GRAVELY: Thank you, Chris. Also, is the volume any better? I noticed we had it down low here, we tried to correct that for those online, so maybe –

MR. VILLAREAL: Um, what happens –

MR. GRAVELY: Okay, you’re back on, Chris. Unfortunately, he muted you. Go ahead.

MR. VILLAREAL: Oh, sorry. The problem that we had on the phone is that we would lose every couple of words from the speaker.

MR. GRAVELY: Is it any better now? Because the volume was down lower on our reception. Is it any better now than it was?

MR. VILLAREAL: I can hear you.

MR. GRAVELY: Okay, well, for those online, and also, Chris, we are going to cover both of those projects today, both I believe in the afternoon, one is before lunch and one is after lunch, so we are covering both of those two projects you discussed, the SCE project and the PG&E projects, in addition to other projects. So, with that, I would now like to go ahead and welcome Dave Hawkins. I guess he’s one of the other champions of storage for around the country, and so PIER was fortunate enough to work with the ISO and KEMA to fund a study a while back, and this is the first time we have a chance to really try to quantify what was going to be needed in support, and so I will let Dave go through the details, and hope at the end there will be five or 10 minutes and maybe we can bring Udi back up here, and David, for questions for the ISO, and we'll start with the audience here, and if we have time, we'll go online, but at least there may be a chance for a couple questions while we have ISO and prior ISO employees here.

MR. HAWKINS: Thank you very much, Mike. The work that we did on energy storage was actually done the latter half of last year and then the report was published this June. It's always a moving target, you know, when you look at something, what is the scope, and what date you have at any particular point in time. The thing that is interesting, of course, when we did this study, the big driver for energy storage was going to be renewables, you know, the big variability of what we're going to see by 2020 and so forth, in terms of the different types of renewables. Of course, today if you look at it, you'll say, well, okay, as we heard from the CPUC, the big driver is AB 2514, that says we've got to come up with a plan for storage, how we going to use it? And I think what you heard from Udi, too, was that the market side has only a small piece of how to value storage, there's still more pieces coming. So, if you look at what EPRI has published, there's a list of about 20 different things, value change that storage can provide, and only about four or five of those things are actually monetized on the market, and so there are things that say, okay, what happens if it's the end user, what happens if it's out on the distribution system, where is it on the sub-transmission system, as well as on the transmission itself. So, as you look at the build out of Automated Demand Response programs, ADR, and energy storage at different levels, there's a lot of things yet to be studied, and so this is one snapshot in time that we did last year to look at this. This is the report that was published, which is available on the website, and again, it's very interesting to think about where we're going and what we're trying to do. Our objective at that point last year was to really kind of model in detail the inter-hour variability. Udi talked about the fact that their production costing simulation models really do a terrific job of looking at how you displace gas-fired generation with renewables, the big impact of wind, and solar, and so forth, on these systems. But the problem is, when you get down to try and look at the minute-to-minute, or second-to-second variability, that is going to be the real challenge, and where is the role of energy storage, and so forth, and how do you really model those. So, this was our project objectives. Again, it was very limited in scope in the sense that we were doing it in a very short amount of time and we did not include the Demand Response piece of it. But we were looking specifically at storage and what would be the amount of storage it would take, how it would in fact impact the ancillary services regulation. And then, also, we were looking at how does storage play off against heat *(combustion)*, I could put in a real fast gas turbine, you know, should I use storage? Or should I use a gas turbine? So there was an evaluation of a 100 megawatt combustion turbine compared to using some amount of storage. And then, finally, what are the policy issues that are affecting all of this? So, again, the goal was to try to take all this data that we had at the ISO of second-to-second, or four-second type data, on a lot of the renewables, play that into a model, and the model that we used was a system called KERMIT, which is more like a Matlab-like model, and so it has all the feedback, control loops, and everything else, and then to actually put together this simulation model and looking at how that would – the second-to-second, minute-to-minute variability, and the role of energy storage as part of that.

We also were not only modeling the way the EMS or Energy Management System AGC system worked, we also implemented the five-minute economic dispatch that the market system does, because, as Udi mentioned, we have this load-following capability at the ISO, it follows all the supplemental energy dispatches, and so you are moving a lot of generation in a fairly short amount of time as you look at some of these large energy ramps.

Regulation people think about is all this 4-second data going up and down, up and down, and you're driving everything up to control frequency, but it is much more than just frequency, you're also trying to manage the ACE or Area Control Error on the interchange, and this is a particular picture of the signal of the actual energy component that goes into the regulation signal. And, as you can see, it doesn't go back and forth over zero every four seconds or every five seconds, or even every 10 minutes, it literally spends a significant amount of time off of zero, which means that the regulation units are providing a significant either absorbing energy or providing energy, which is a problem when you start looking at short-term energy storage. So, if you've got a five-minute, 10-minute, 15-minute energy storage device that is trying to provide that regulation capability, it's going to run out of energy. And so this is part of the problem is, as you look at those overall regulation signals that are coming, and so forth, this is an issue of how much energy does the storage devices have to actually provide. And you can see, there are periods where this – this was from October of last year – periods where we were down almost 400 minus and almost 400 plus in terms of the regulation energy component that is going up and down, as well as the frequency peaks. There are those that say, well, let's just carve out the frequency piece, but if you're from the ISO dispatch perspective, that's way short of the kind of resources that you need, you can't do just frequency. If you just did frequency, you could have a little frequency meter on your device, and whatever, and you could run it up and down, but it doesn't really give you the kind of control signal that you absolutely have to have if you're going to meet the NERC control performance standards. So, you have to deal with the energy piece, as well as the frequency regulation piece.

So, some of the highlights of what we did, we actually simulated about 250 different generators in detail, and what their ramping capability, the ability to move within the hour, we put in all the 4-second dispatch signals, and we also put in all of the variability that you get out of solar and wind generation, and looked at all the ramping and so forth that is going to be within those areas. And the thing that is interesting, we also not just modeled California, but we also included the inertia and the import capability coming throughout the whole Western interconnection, so we have the inertia components of that, and about half of the study effort was to make the model simulate the way the real system worked, so if you took a real day, with a real big generator trip, and looked at the variability and things that happen, you'd like to have your mathematical model produce the similar type results, or very similar results, as to what the real system did. And the thing that's interesting is mathematical models have absolutely perfect response, and the Western Power Grid is a little less than perfect, and so what we learned to do was to put some inertia of slowdowns and some feedback loops and things that would slow down the mathematical model so it didn't act faster than the way that the whole Western Power Grid does. Again, this is the time domain periods that you're looking at, and so the analytical piece is basically looking at the second-to-second, minute-to-minute, and out to about an hour type variability. If you're looking at a big energy shifting, then, of course, you go into basically a production costing model.

The KERMIT tool, as I mentioned, did represent the inertia from all the other parts of the Southwestern Area of the United States, the Western part, Colorado, as well as the Pacific Northwest. At that time, because the ISO was also, you know, had the data for the whole Western Grid because we were doing the – I can't think of the word – anyway, the coordinators for the WCC for part of the system

– the Reliability Coordinators – I couldn't think of the word – we also had the data on all these interchange data and so forth, so that gave us the ability to do a very thorough evaluation of the system and, again, as I said, this is a big model for all the different parts.

Because we had a limited amount of time, we could only look at summer, fall, winter, spring type days and do snapshots of those particular days and do them in detail, and then, of course, we looked at 2012, which was our 20 percent scenario, and also 2020, and again, in 2020, what we're looking at is a low amount of concentrated solar systems and different amounts of wind, and trying to put those particular scenarios together. Was this the perfect way the system is going to build out? Probably not, and nobody would ever guess perfectly as to the way these build out. So, this was trying to put some ranges and extremes into the system as we looked at what those look like.

For the wind generation, then, we picked some days, those specific days we had picked which was the July, October and February, and basically what we would do was scale those up for the different pieces. So, whatever you had for north of Path 15, south of Path 15, as your specific data, it was simply doing a scaling up to the larger amounts of 6,000 to 10,000 to 13,000 amounts of wind, and the concentrated solar. We had a very limited amount of data, of course, there was only at that point about 400 megawatts of concentrated solar, which we escalated up shamelessly to a thousand, to 3,000, to actually up to 7,000 and 10,000 megawatts of concentrated solar. Again, you would get some diversity, but you have to remember, a lot of the concentrated solar will be built out in the Mojave area, and so you do not probably get as much diversity as you would get from PV. So, if you had PV in the north, PV in the south, PV in San Diego, you'd get a lot more solar diversity, concentrated solar is going to be in those areas down in the southwest where there are lots and lots of sun and very low cloud cover, even if you import some of the concentrated solar from Arizona, the time shift is fairly insignificant for when it actually ramps up. And even if it's way out of Colorado, the time shift is only an hour, and so whether it's ramping up at 7:00 in the morning or 6:00 in the morning, it is still – it's not a big time shift that you're going to get on the solar. PV, as I said, we had a limited amount of PV. The expectation is that you get a lot more diversity, it doesn't ramp the same way, it has more of a hyperbolic shape, and of course we're looking at 3,000 megawatts of PV. So, you start putting all of those together and you get pictures that look like this, and so you see, like at 8:00 in the morning, the wind has fallen off, you're down to about 2,000 megawatts, and the solar takes off and does this huge ramp up to, you know, 6,000, 7,000, 8,000 megawatts within a few hours in the morning period. It turned out, as part of our simulation study, then, that the big ramps up – and again, the big ramps down at the end of the day, when the sun goes down, the solar is gone. And, so, as you look at all of those big ramps, that became one of the dominant factors in our simulation studies.

Again, this is a picture of what the – the blue squiggle across the bottom is basically what happens to your ACE, or Area Control Error, as you get these larger and larger amounts of renewables ramping in and out, and you can see the ACE in this particular case went down in the morning to a minus 2,000, and at the end of the day, when the solar ramps out, our import, or the amount of energy that you are needed, the ACE goes up well over 2,000. So, you see some pretty big variables, and the fact that they extend for not just seconds or minutes, but they're out there for almost an hour, really is going to draw a lot of ramping of energy resources and, so, those fast gas turbines and energy storage devices are going to really be challenged because there is a lot of energy to move in a fairly short amount of time with these kinds of pictures.

So, this is a picture of the high solar type picture and then this is one with four hours worth of energy storage vs. one hour worth of energy storage vs. – one of the things we did with the model, by the way, was we told the model they could have an infinite amount of storage, so you start out with saying you can use whatever you need, and then your ACE, then, becomes this little green bar across the bottom, and you perfectly meet everything that you have to do, and then you say, well, “Okay, how much did the model actually use?” And then you start ratcheting back to, you know, four hours, three hours, two hours, and then you watch what happens. And you can see, in this particular case with the big red line, even one hour’s worth of energy storage really did not work, two hours helps a lot, and the four hours made it perfect. So, certainly, the two hour may be a credible economic level of storage that you’re starting to look at, at least that’s what we were seeing as part of these simulation studies. Again, this is an April day. One of the things that Udi mentioned is the challenges we have in the spring time with a lot of units are offline, the renewables are going to displace most of the gas-fired generation, you will still have your hydro systems on, but you have very little margins left in the springtime for units with lots of inertia and lots of ramping capability. So, the periods that are going to be real challenges are probably the shoulder months, spring and fall. Summer, you have everything turned on, and so you have got lots of capability of things that you can move, and so you may have your 20,000 megawatts of regulation available in the summer, but in the springtime, you've got a lot of units off for maintenance, and you have very little room left; if you've got the wind blowing, maximum, and of course the solar is starting to come on as you get into those warm days of May and certainly in early June. So those will be interesting periods as you look at the different seasons and the things that you have to do.

One of the things we had to do was try to figure out what units we would actually have on as we moved out to 2020 and, again, we had the same problem that the ISO has talked about, is that you get a lot of your units are displaced. So, what are you going to de-commit? And so, we didn't have enough time to run all of the production simulation models that we would like to have had, so we ended up with what we call the poor man's de-commit, so you take the oldest units with the highest heat rates and say, I bet those are the ones that are going to be forced off, and so, as one way of getting there, is you start knocking off those and down the list until you have just enough thermal units left on to meet your basic requirements, and then you make room for all the renewables that are coming on. So, that was our particular way of going about it and, you know, we thought it made a reasonable level of having the right amount of units on.

So what we learned is that this particular independent study really came through in validating other studies that the ISO was independently doing, so that we were looking at increases in regulation up to as much as 800 megawatts during some periods, and as we went to the year 2020, it looked like 1,600 megawatts of regulation would be required. And, again, that fairly validated other types of studies, so that was reassuring that the KERMIT type model we were using was on the right track.

Again, we did not put in – you know, one the things that was criticism in the study was that you'd say, well, gee, Mike Gravely, you can certainly forecast what time the sun is going to come up, you know, the ISO should be able to forecast when you're going to see that big solar ramp coming on in the morning, and start moving units in the right direction, and so forth, so that you've made room for it, so you don't have to use quite as much storage. And that's probably true, and you can forecast pretty accurately the time the sun is going to come up, and you can forecast when those units will ramp. The biggest thing we found with concentrated solar, it would go from essentially zero or slightly negative as they warmed up the plant, to its full output in less than an hour, and so those were fairly large ramps. Now, the question is, if I forecast, and you know, Jim Detmer says, "Well, what time is the sun going to come up, are we going to see these?" And I say, "Well, it's between 7:00 and 8:00." And so, we set up the system and, lo and behold, we had some unexpected cloud cover, and it's an hour or two hours late. What happens then? Do you have enough other resources you can call on to cover that shortage? And what do you do? And so the forecast error and how much reserves you have to carry, and so forth, is always going to be an essential part of doing some of these studies.

Another part of it that we would love to include in the future is, okay, what loads could be moved at the same time, that would only have to move for 15-20 minutes, which would slow down the rate that you'd have to move some of the thermal or other hydro, and give you a little time for those units to catch up, so there's more things to be done. Again, we did not – we modeled the pump storage units as either a generator or a load – if you're doing these studies in the future, what you'd like to do is take compressed air, pump storage units, and so forth, and do the actual more detailed modeling so you can actually show what is the turnaround time. So, if I'm going to go from a generator to a load, you know, to pumping, or I'm going from the pumping mode and I want to turn around and go into generation time, do I do it 15 minutes, 20 minutes, what kind of time lags, and what are the impacts of particularly compressed air energy storage? How much do I have to count on that thermal storage to heat the air back up, coming into the units, and so forth? So, there are new additional kinds of modeling things to be built in those areas. The other thing we were asked to look at was, well, how effective is storage vs. just buying another combustion turbine. We've all heard that gas prices are going to remain low, we now have twice the amount of gas of Saudi Arabia's oil, so, you know, gas prices apparently are not going to escalate. So, you say, "Okay, we can still do it with a gas turbine," and that's true, but what we've discovered with this is that, because a energy storage device can go both positive and negative, where a gas turbine basically ramps up or it ramps off, it turned out that about 50 megawatts of storage was about equivalent, it got the equivalent effect that you would get with 100 or 110 megawatts of combustion turbines. Again, if you wanted to meet greenhouse gas requirements and so forth, you're going to find that the storage is the more effective solution.

This is, I think, just a summary of some of the other – of the data that we've already talked about in terms of how much storage at a watt, and then, again, a graph of – you can see the 3,000 megawatts of storage, man, it solves everything – it's expensive, but it does solve all the problems with ACE. The 2,000 megawatt helps mitigate it some, and particularly during some of the periods, but it's not the perfect solution. Again, this was another summary. The other thing that was interesting that we discovered is that, not only do we have ACE problems, but we also started to see a deterioration of the ability to control frequency, or to meet the frequency control standards that are set by NERC. The deterioration was not large, we didn't violate the standards, but it certainly was going the wrong direction, and there was a significant degradation as we went down to, you know, in the 150's and 160's, where we normally are up in the 180's and 190's percentage of meeting those standards. So, I think this is just a reiteration of one of the pictures that I had. So, policy recommendations, one of the things that is interesting is the storage tends to be very fast, certainly the lithium batteries and other types of things will ramp from min-to-max in basically a second or less, so there is – and the question, then, that is always posed is, well, is there an additional premium or a benefit from the fast storage? One of the other studies that has been pursued is the idea of putting a storage unit at a generating plant, and then, as the ISO sends out its signal, that you can actually do a decomposition of that signal at the plant, and take the fast regulation piece and put it into the storage device, and take the slower, larger energy pieces and put it into the generating unit, so you have to move the generating unit less, and you take advantage of both those type systems. The large generator, then, also provides the missing energy piece that has a very limited amount that can actually come out of the storage device. So, that looks potentially interesting as one of the ideas of pursuing that. And we certainly see validation of the stuff that Udi was talking about, of increasing the amount of regulation. The problem we see now, at this point, if you looked at the latest regulation prices, even though the ISO pays separately for reg-up versus reg-down, if you took the numbers for the last three months of, say, August, September, October of this year, and you added the reg-up, reg-down, prices and you did the averaging, the average turns out $8.65 -- $8.65 for regulation is probably not going to pay very profitable for an energy storage device. The East Coast, other places, seem to be more in the $30.00 - $40.00 range, so regulation looks much more interesting to Beacon Power back on the East Coast in New York, and it's probably a tough one to pencil out yet on the West Coast with that kind of number, but it's interesting. As the amount of regulation that we have to procure goes up, is that going to drive up the price? Perhaps, but there seems to be a lot available. Anyway, more things to be done. Was this a perfect study? No, it wasn't. We had limited amount of data that we looked at, but we think we certainly validated the fact that we have a new model that we can use for the intra-hour variability studies. And so, I think the goal was to understand the impact to renewables, we've really, I thought, pushed the envelope a lot, and the concept, too, of using new AGC algorithms is something we'd like to promote, and the idea of having separate kind of loops for how energy storage is used, and so forth, will go, I think, a long way for providing the better solution. And priorities for future work is, again, we'd like to see more development, more days that we test, we'd like to put in the Auto-DR piece, and we'd like to extend it out into more the distribution type system areas and look how the whole complement of Demand Response and energy storage are played together. I think that's it. And so, we certainly proved that energy storage is viable, it can do some fairly interesting things, whether it is financially going to make it work with $8.65 for regulation, probably not, but there are other things it can do. Thanks.

MR. GRAVELY: I'd like to give a chance – so for anyone in the room here, we'll start first in the room here, give them a chance since we have some ISO experts here to answer questions, and we're talking about the primary focus today is Grid support. I'd like to throw it out for the audience, if you'd just go up to the mic and ask your questions so people on the phone can hear you, please. The mic should be on, go ahead.

MR. SCHAINKER: Yes, it is. My name is Robert Schainker with the Electric Power Research Institute. First and foremost, these last two presentations were fantastic, thank you, gentlemen, for doing excellent work and just to show us that we need more work to be done, that is for sure. My question relates to the situation that there is a lot of transmission constraints in the state, as well, and I'm not sure to what extent, and that is my question, you included transmission constraints in all those issues, that there's so much ramping and regulation going on at different times of the day in these predictions, it would seem that maybe you have some views or observations about transmission issues.

MR. HAWKINS: Yeah, for our particular study, we did not include the transmission constraints, what we basically did is a system-wide study, and certainly in other work that we've done, we've looked at the fact that, if you have regulation units that are behind some kind of transmission constraint, you may not get all the regulation range that you may think you're going to get. There also were times where the amount of – the impact of moving units that are on regulation, off of their energy subpoint, and then leaving them up there for a period, also exacerbated the fact that you had transmission all resolved they had with the energy schedules, and lo and behold, I take some unit out of regulation and I move it up 50 megawatts, and then start moving it, you know, during the hour back and forth there, and I no longer have an optimum transmission loading pattern anymore, and so there are some really other interesting constraints that one has to look at in the future. In terms of optimum location of, for example, energy storage, one of the things that we've kind of come to the conclusion is that the closer you get to load, probably the better off you are, but if you're working on transmission, you're much better of looking at, say, a congestion point where a number of renewables all come together, and so, if you are looking at some major transmission point on north/south transmission, and trying to mitigate transmission congestion on path 15 or path 26, the closer you had energy storage – a large energy storage – to those particular locations, you could do some fairly interesting thing with transmission. That was beyond the scope of this particularly study, but has been looked at as part of other studies.

MR. SCHAINKER: Okay.

MR. HELMAN: So, neither of the studies that I mentioned has a detailed network model, but the 33 percent study has a WEC-wide model on a zonal basis, and it will show some results of, if you reserve capacity on the

California power system for integration purposes, what impact that has on WEC-wide flows at that level of aggregation. So, yeah, it's not as detailed, but we certainly have as part of our research agenda, to move on to more detailed network models in the next round.

MR. SCHAINKER: Okay, thank you very much. Very very interesting.

MR. GRAVELY: Any other questions? Okay, well, thank you very much, gentlemen. We appreciate it very much. So, we will now move into some of our more specific ones, and John Minnicucci is going to talk a little bit about SCE's strategy for storage and their activities, and we'll be hearing later about some of their projects.

MR. MINNICUCCI: All right, let me test this thing out real quick. Perfect, all right. It's great, I work in Advanced Technology and I can't figure out how to run this slide deck. Anyway, good morning, everybody and thank you for having me here. I appreciate the opportunity. I've got a lot of stuff to go through and a short time to do it, so I'm going to move through this stuff pretty quickly. If you have any questions, I'll be here all afternoon, as well as Alex Morris, who is setting in the back probably hiding at this point, any questions, you know, feel free to ask us, we'll give you our cards and whatnot.

All right, with the short presentations, I like to provide an Executive Summary, some key take-aways. SEC has a long history with energy storage. We approach it from the technology standpoint and from the strategic standpoint and what can the technologies do and, you know, what do we need them to do. Our approach to energy storage is from the perspective of system needs and applications, as opposed to just the technologies. SCE, like the CAISO, is technology agnostic. You know, whatever works and whatever hits the right cost point is a thing that we definitely want to use. Energy storage, obviously, is a broad category of operational uses and technologies, you've got everything from super capacitors, very quick acting, to large-scale pumped hydro, and it's a huge huge category. And then, I guess the primary challenge facing us is, okay, well, what are the best technologies? What are the specific and practical uses that are cost-effective? As I said, we take a bi-directional approach to things, we look at it from the technology standpoint, which is what can technology do, and we also look at it from the strategic standpoint, what do we need it to do? Historically, we had a Chino Battery Project, which was a large scale 40 megawatt hour project we did about 1988. We found that the technology works, and I'm looking here at Mr. Schainker, did the work with EPRI and a whole host of other partners, found the technology works, it just wasn't cost-effective, and so it wasn't something that became deployed. You know, where are we at today? Well, you know, those types of things might be cost-effective today. Our EV Tech Center, I'm sure that most of you have heard the EV Tech Center, it's something we started in 1993, and we've tested a whole host of electric transportation technologies and battery technologies for home energy use. It's the SCE facility that President Obama visited last year, that was a big plus for us, that's the first time a sitting President had visited an SCE facility, and we were very proud to have hosted him. The Tehachapi Storage Project, I'll talk about on the next slide, as I will the revised Smart Grid demonstration. So, let's jump to the strategy side.

Understanding what the technology can do will really help us to look at, okay, well, is it a potential solution? Is this something we can use to address a distribution problem, a transmission problem? Is it something our customers might be able to use for interruptible power or if they want to do some market arbitrage, or if they want to supplement the solar on their rooftops, you have to look at the application, not just the technology. And then, if you look at bullet point 3, storage is a huge huge category, it's not something that Edison can do on its own. You know, we need to work with folks like EPRI and the CEC, the Department of Energy, CAISO, with vendors, A123 is one of the vendors on our Tehachapi project, it's a big issue and if we don't work together and collaborate, it just takes longer. I don't know that we get there without collaborating, to be honest with you. And then, finally, the last bullet on the strategy side, this is looking at a roadmap. You know, there are so many technologies, there are so many ideas, and there are so many potential uses for the technology that, without a roadmap, it's really hard to keep track of how everything fits together and who is actually doing what. You know, PG&E, for instance, is going the compressed energy storage up north. Well, I don't know that SCE needs to do one of those when we've got our sister utility up north doing it with EPRI. And I believe it's also co-funded by the CEC. So it's just one of those things that we, again, need to work together and keep track of how all these things fit.

Our primary storage R&D efforts, I'm hoping that Chris Villareal is still on the telephone because SCE did sign the contract with the Department of Energy, yeah, we are very very excited, the Tehachapi Project is moving forward. Again, that is a utility scale lithium ion battery, we're going to use that for, I think there are 13 different capabilities that we think we can use it for on the Tehachapi system for wind integration, and whatnot. Very excited about the project, cannot wait to get that thing moving. The next project is the ISGD – I'm sorry, we call it the Is Good [ISGD] project internally, it's the Irvine Smart Grid Demonstration, and as part of that project, we have a large transportable battery system or a battery on a trailer. We want to test that system for distribution purposes. If you have a circuit that needs help, you know, during a summertime peak, it may need upgrading, there may be different customers that come onto the systems with, you know, either PV or whatever, that change the dynamic of that particular circuit. We think that we can use this type of technology to move in and keep serving customers reliably until we can go out there and actually upgrade the circuit to meet future needs.

Community energy storage – this is not a mobile energy storage device, this is something that we would put at a distribution location and, again, this would help with customer installations, either things that are using electricity differently than they currently are, or things that are feeding back like distributed energy resources, photovoltaic's and whatnot. So, we do see storage as playing a pretty key role. Obviously we're looking to test it. And then you get down into the residential home energy storage, you know, how is the storage going to work with the home area network, with plug-in vehicles, with the solar panels, all of this stuff has to work together if it's going to be a serious solution, you can't just have one thing work and harm all the other things. So, that is our Irvine Smart Grid demonstration.

This slide is the slide that I would like to have flashing and, you know, burn into everybody's retina because the needs and policy goals drive solutions. You have changes to system inertia, you know, the once-through cooling, don't know exactly how that is going to impact things, but we expect that it will impact things very significantly. What are the tools at our disposal to continue providing power to our customers reliably? Well, we think storage might be one of those types of tools, but that's a big issue to solve, so that's just an example of how policy drives more than technology drives. Again, we want to identify potential solutions, there are a whole number of solutions for any one problem, we want to understand what all the potential solutions are, and then test those solutions. Obviously, we're not going to do a Tehachapi style demonstration for every particular deployment that we want to do, there are others that are doing these types of demonstrations, and we hope to learn from that, but we do want to understand, you know, what is the capable – testing proposed solutions. After you do your testing, obviously you want to communicate your findings. The thing that is great about doing a DOE or CEC-type project, or an EPRI project, is the information is made pretty much publicly available, and that helps all of us to understand, you know, what the state of the technology is, where things are moving, what works, what doesn't work, what particular applications these things work for. I think it's very important to have that open innovation. And then, you know, the final is you need to look at the results, do a cost-benefit analysis, and really – this may be the greatest technology in the world, but if it costs 50 times more than the benefits, well, I don't know if you go with that. Now, it's really difficult when you're trying to solve a policy problem because, you know, the cost benefit really – I don't know how much that plays when you're ordered to do something, or you're trying to keep the system up and running when rules have changed, or whatnot. But, anyway, that's kind of how we look at policy and how policy drives technologies.

Now, as far as just a barebones, cut and dry approach to assessing energy storage, we identified the operational uses and understand the technologies, this is just basic stuff, you develop your practical applications – applications are system specific, different distribution feeders have different, you know, nuances. There are different customers, there are different types of distributed generation, there is a whole host of, I guess, nuances that require us to do things differently for each specific application. There is no one-size-fits-all on the electricity system. You match the applications with the technologies and, finally, you've got to evaluate it, you know, what is going to make sense? Again, if you've got something that is very very expensive, what's the impact to California ratepayers? That's something that concerns SCE and I'm sure it concerns the other utilities, as well. We want to be able to do what we do, but we want to do it at a reasonable price.

I'm sure that most of you have seen kind of how the technologies work and what some of the uses are going to be, so I'm not going to spend a lot of time on this slide. I do believe this presentation is available on the CEC website, so if you had any questions on where we think some of these technologies might play, this is not an exhaustive list, it's just an idea of how we see things working. And here is kind of a look at the technology overview. Along the vertical axis, you've got your discharge time, not just in quickness, but also in duration. If you look at the lithium ion, the yellow oval there, the reason we went with the lithium ion battery at Tehachapi was that you could make it bigger by stacking additional components, so you could get your megawatt power up, and it's fairly quick in reaction time. And it's also got a pretty good duration, as well, so that's kind of why we chose that specific technology, as opposed to some of these other technologies. It's what we thought we needed for that purpose. But this kind of gives you an idea of what technologies might fit what specific requirements.

Practical Storage Applications – I've only got three examples here, we actually developed 12, and if you wanted to see those, we will probably put them up on the Edison website and we can send that out to everybody. But, you've got all different types of applications here, you know, the first one is more of a generation application, you know, you've got wind that blows at night, the peak is some time during the mid-afternoon, so you know, what can you do to make those two match? Or actually, honestly, I think it's more of an economics discussion, you know, for the generator. You can probably make a little bit more money if you can provide that power at a better time. So, that might be something practical that you can do with storage. Peak shaving, you know, something more down on the distribution level. You know, our distribution circuits, some of these circuits are fairly old, and with all the changes to the circuits and all the new technologies, you know, we think that energy storage can help us to shave peak and maybe avoid some congestion on our own systems, so, you know, we see a practical application there.

Finally, at the end user, with people going solar and all of the incentives and things that are out there, you know, I forget who had said it, but the sun goes down at night and there's no more solar. So you need some type of storage application if you do want to be entirely off the Grid.

Conclusions. Valuing energy storage is a key issue for all of us, we need to know how much it is going to cost, what works, how can we do this together. I think there are a number of efforts that are going on. I think that, as we do these DOE projects and some of the CEC projects, then ISO, we'll be able to better understand how to go about valuing these things and really identify what the best technology is for which purpose. And then, obviously, at the end of this thing, there is a lot of work that remains to be done, and I think collaboration is absolutely essential to getting it done. Questions?

MR. VARTANIAN: John, Charlie from A123. If you could speak a moment about the study component, my understanding is the CEC, even in advance of the DOE and the State, had funded Edison to do simulations that helped to establish some of the foundational characteristics and requirements, if you could speak to how you're going to extend that work?

MR. MINNICUCCI: Absolutely. The CEC did – they actually funded two projects, one was with SCE to look at its transmission system and to determine where we might – where storage might be the best approach to addressing some of the issues. Obviously, in the Tehachapi area, there is a lot of wind resource that is variable and we identified a specific substation that had the right square footage, had the right – honestly, it had the right everything from all the environmental issues, all the way down to what we could do with the battery. Charlie works for A123, used to work for Edison, and he helped us with some of that work. And frankly, that study was the genesis of our proposal to the Department of Energy. Does that cover it?

MR. SCHAINKER: Robert Schainker. Very good presentation, thank you so much. I know that Edison is literally a world leader in electric vehicles and obviously electric vehicles have a lot of battery technology in them. I thought maybe you may want to comment on electric vehicles as what Edison might think about in terms of energy storage and the Grid size to accommodate the electric vehicle potential on loading, either people plugging in at work during the afternoon, or at night when we would prefer them to plug in to re-charge. I'm sure you're familiar with all this.

MR. MINNICUCCI: Oh, absolutely. Right now, as I'm sure everybody is familiar, the CPUC is actually holding a rulemaking on exactly those topics. Electric vehicles are coming to California. We believe there will be about 74,000 over the next – I think it is by 2012, in our service territory. Our distribution systems, again, are not necessarily made for that type of additional load, so we’re going to need some type of technology to beef up our capabilities. We’ve done some very detailed assessment on where we think the deployment, or where we thing customers are going to purchase vehicles and plug them in, and we’re looking at prioritizing upgrades to those systems, which will include everything from upgrading transformers, which are not going to get a chance to cool off at night because we’re hoping the vehicles are going to charge at night and make use of some of that wonderful wind energy production, and also, as I had talked about with the distribution level storage, I think that is something where I think it is going to be essential to helping us meet our customer energy requirement over the next few years.

MR. SCHAINKER: Thank you very much, John.

MR. MINNICUCCI: You’re welcome.

MR. GRAVELY: Thanks, Mike. Hopefully the mic system – we’re now using two mics in here for speakers, for those people online. We’re getting a lot of feedback, so hopefully it is better. Now, I’d like to bring up Doug Divine from Eagle Crest Energy and we’re now going to begin to look at one of many presentations today, which is technology specific, very large storage, and, again, one of those technologies that we see as on the horizon.

MR. DIVINE: Great, thanks, Mike. I'm Doug Divine, CEO of Eagle Crest Energy, a pump storage developer. In addition, I have two of my colleagues from the National Hydro Association, Don Erpenbeck of MWH and Rick Miller of HDRDTA here to help talk through some of the issues on advance pump storage, to assist with renewable integration, grid reliability, and renewable load shifting.

We see pump storage as one of several technologies that can partner with variable energy resources, but right now, pump storage is the only commercially proven great scale energy storage technology from 40 megawatts to over 2,000 megawatts. So, existing pump storage projects in California such as Helms and Castaic were built to complement nuclear plants and off-take excess energy at night. Today we will discuss the changing uses of pump storage to meet today's requirements.

So this is a different version of that Edison chart. What I've done, I've taken out the log-log because it just makes it easier for me to look at. So, pump storage today provides solutions, again, anywhere from 40 megawatts to thousands of megawatts of energy storage, and is a part of the solution going forward, and we're here to say that wholeheartedly. Pump storage is probably the easiest of these technologies to explain. Water flows from the upper reservoir to generate electricity when energy is needed. We pump water uphill when excess generation is available, at reasonable cost. We're going to talk today about some of the changes in technology, some of the new technologies that make pump storage even more applicable to solving the solutions of intermittent energy with renewable energy resources. We'll talk about adjustable speed units, which have very fast response times, and the ability to go very low load operations, and it will allow for numerous cycles per day, unlike some of the existing facilities, which were designed to cycle once per day.

And now, Don Erpenbeck will talk about some of the technologies, the advanced technologies, and the benefits they will bring to the system.

MR. ERPENBECK: So this next slide, actually the next four or five slides, we were invited in to NERC last week to talk a little bit about what the capability of pump storage really is, and one of the things we realized is that people don't understand what the pump storage fleet is doing right now. So, this shows the different types of response times. The green line represents adjustable speed machines, which are the new state-of-the-art technology, and there are none of those in North America presently. The black line represents single-speed synchronous generators, and you can see that frequency regulation is much higher with the adjustable speed machine, but the one thing that is different with the adjustable speed is we can do load-following and frequency generation in pump mode because we can have an adjustable pump. An adjustable speed machine with a 10 percent speed range, a 350 megawatt machine would have about 125 megawatts of adjustable decremental range up and down while it's in pump mode, where a synchronous machine, once you closed the breaker, you're pretty much fixed based on hydraulics.

This one shows the difference in operating range. Now, the blue line is a synchronous machine, older machines are operating above that rough zone from about 60 percent gait up to about 100 percent, and newer machines where we're replacing the runners, even at the older plants, are now operating down in that 20-30 percent range, and they're sitting down there basically idling, waiting to ramp up. The adjustable speed machines give us a much higher efficiency range across the board, it'll give us a 3-4 percent if we were running at peak efficiency all the time, but since pump storage is not really dispatched on a technical basis, but on an economical basis, it really could be more like 10 percent in terms of total efficiency performance and the difference between a synchronous plant and a adjustable speed plant. And so you can see a much wider operating range on the high end and low end. Machines can operate in the rough zone, it’s just that we require some injection air, and so there is a little bit of a dead ban sometimes for a lot of these older plants in North America, that sort of sits in that 40-60 percent, and an adjustable speed, we can really squeeze that down so that we almost have none.

An adjustable speed pump storage machine is a flywheel. We can run – these are large inertia machines, we can run these as flywheels, we can give up speed in the speed range and produce positive megawatts in the adjustable speed mode, we can do it in synchronous condense mode, we can do it in pump mode, we can do it in gen mode. We can play with the frequency range to do what we need to. The two graphs on the right represent the difference in a transient situation over six seconds. The top one is a synchronous machine, how it responded in Austria to an event, and then the second one is what the adjustable speed machine does to the voltage. And you can see the red line is basically flat-lined in terms of the active response, in terms of the seconds.

One of the things I want to talk about and mention is the ramp rates. Pump storage projects right now are ramping at between 5-10 megawatts a second, from those part-load operations, that's the normal what they're doing in California and Arizona right now, that is on unit basis. On a plant basis, Castaic's six units can do 40-50 megawatts a second, and they're getting called on on a regular basis. when you talk about the KEMA study and transmission constraints, their way that the grid is dealing with it is by dispatching the pump storage very fast. And the adjustable speed improves the frequency response and through the power of electronics and a router and what it can do in terms of frequency, and how fast it is. But the overall performance is more of a hydraulic one.

The last slide on sort of technical performance is mode changes. This is the fastest pump storage plant response time plan in the world, it's in North Wales, called Dinorwig, it's about 2,200 megawatts right now, and two units are pretty much turned over to the transmission grid at any one time. This project can go from full pump mode to shutdown and generate in under eight minutes, from full pump output to full gen output in under eight minutes. It does a ramp rate of about 2,300 megawatts a second per unit, and 50 megawatts per second at a plant level. This plant is basically the way they integrate renewables and generation in the northern part of the UK, but you can go from spin to generate, so synchronous condense to generate in 12 seconds, from spin to pump. So this is a conventional synchronous machine, this is not an adjustable speed plant.

So, now to sort of go to the future and what's going on around the world. One of the things that is changing is most of the pump storage projects that are being built now are either utilizing existing reservoirs that already exist, or they are closed loop systems, which means they're fully self-contained, they're filled with a stream, or from ground water, and they're very environmentally benign. Some of the NGO's have even come flat out and said it in writing, that they do not have an objection to most of these systems. They would want to look at each one on a one-by-one basis, but that they can support this type of renewable integration. What is the rest of the world doing? Rick is going to talk a little bit more about some of the specifics about how they're integrating wind in Europe, but you can see right here that the U.S. has 18,000 to 19,000 megawatts of nameplate, but it's really closer to about 24,000 megawatts of pump storage, that is two percent of the U.S. grid is currently pump storage. California has almost 4,000, about 3,500 megawatts of pump storage, of which the first block of 400 was built by WR Gianelli in the '60s, the second block was 1,500 megawatts at Castaic, was built in the '70s, Helms was built in the '80s, and there have been none since the mid-'80s, since Helms, but you can see there is a little job in the U.S. for 40 megawatts down in San

Diego that San Diego County Water Authority, that very bottom of what's under construction. So you can see in the world, Europe has almost 40,000, Japan has almost 10 percent of its grid, it's pump storage. Now, the right-hand graph shows what's under construction, there are three projects under construction in Spain alone due to wind integration. There are two in Switzerland, there is one in Austria, there are about 6-7,000 megawatts that are in early – will be breaking ground here very shortly, they're not shown here as under construction fully yet, but you can see Portugal, Spain, Switzerland, with almost 2,000 megawatts. So, you can see from this graph that the rest of the world – and if you look at the European versions of these wind integration studies, they all come back to hydro pump storage and other forms of storage. They are complimentary to each other, they're not the same.

So the pump storage trends in Europe, they are building pump storage projects to integrate their wind; that is the trend that is going on around the world. They're looking at 20 percent wind integration and the ENSO area is supporting large transmission projects to help reinforce the interconnection of all these different pump storage projects. So, Rick Miller here is going to introduce some various aspects.

MR. MILLER: Thank you, Don. And again, to focus on this, what's happening in Spain and what's driving the development of grid scale storage in Spain is lack of transmission interconnection with the rest of the European Union. Spain and Portugal, the Iberian Peninsula, has a very weak interconnection with the European Union, so therefore they have about 14 percent of variable generation and, as part of their grid, they're building three pump storage projects today. They don't have any other options for grid scale storage. What's happening in Denmark? Denmark is used as a benchmark for wind and variable generation integration. How does Denmark really work? Denmark is a part of the North Pole, it doesn't do its own balancing. And it has strong interconnects with Norway, Sweden, and Germany. And it utilizes the conventional generation, the conventional storage in Norway, to integrate – there are 3,000 megawatts of wind energy. Here is Denmark, you've got strong interconnects in Norway to the north, and Denmark as a system is very inflexible, it is a must run distributed generation system of central heating plants, a very small number of large central generation plants, and a very distributed wind pattern, but in a small geographic area distributed around the country of Denmark. And the way Denmark works, there is a 1:1 correlation with energy flow over the power interconnections to Norway with wind output. The red line at the top is wind output, this is in the winter season where it's a high wind output season, and if you have the – if you look here at the top, you have high wind output, you have high energy export to Norway, where you have low wind output here, you have – Norway is re-importing – is exporting the energy back into Denmark, so it is on a grid scale, it is utilizing the large storage that is available in Norway and their interconnection, so the message is, where you have not a lot of flexibility in your generating system, you've got to be connected to another flexible system in order to make it all work.

The industry has been working with Bonneville Power to help them figure out their challenges every day. This is a relatively busy slide. The message here is, well, this slide and this study will be coming out on BPA's website in the next few months. To walk you through this, the top line is load, the red line is variable wind, and the blue line here is net load. This is what your non-wind assets within the BPA Balancing Authority have to respond. This – and the key point here is the rapid ramping that is occurring every day on the Bonneville system. This is a day in June of summer of '09, and this really validates the KEMA study, rapid ramping of thousands of megawatts in an hour is the future where you have thousands of megawatts of variable generation. And then, of course, if you look at the high ramping here on this day, where it's out of phase with load, you have wind coming up, load dropping down here, the dark blue line, your net load is your non-wind assets where they have to be basically shut down in order to have the system balanced. We integrate storage into it, this is the bright green line here. What that shows is the re-dispatch of the Columbia River system, you have a more stable power output and greater grid reliability.

This is the U.S. market today for pump storage, there are 40 projects, as Don mentioned. The bulk of those are in the east. Here is the future. There are about 60 projects in front of FERC today for preliminary permits, representing over 50 gigawatts of energy storage. The bulk of these are in the Western U.S., again, driven by the variable generation market opportunity, and the needs for greater reliability. NERC's biggest challenge is in the Eastern interconnect where we have very little grid scale storage being proposed. NERC is very concerned about future grid reliability due to the rotating inertia that will be decommissioned -- potentially decommissioned -- over the next three to five years. And I'll turn it back to Doug.

MR. DIVINE: Right. California clearly knows a lot about pump storage, a rich history with pump storage with projects like Helms and Castaic, and there is currently a proposed project, 6,000 megawatts currently under development in California. And among other things, the development of pump storage here does assist with some of the air emission issues, also, with the ability, again, during periods of renewable over-generation to take that off-peak power and deliver it on-peak with no additional emissions, very beneficial. So, in building what the KEMA report and some NERC studies, storage is a part of the solution going forward for intermittent renewable generation. And we believe that the new pump storage plants using some of the adjustable speed technology can be a part of that solution. As we talked about adjustable speed turbines can at times act like a flywheel providing very fast response. In addition, some of the utilities and developers are looking at economically and environmentally advantaged sites with reduced construction and reduced environmental issues. And finally, as Rick talked about, in Europe and Japan and Asia, pump storage is a part of the solution being implemented today to deal with these kinds of issues.

Of the eight projects currently being permitted in California, we would expect at least a couple of those to move forward in construction in the next four to five years, providing in excess of 2,000 megawatts of capacity. There are certainly markets in California for pump storage, we've talked about that, but with the large capital costs of these projects, there are certainly challenges in developing and getting these projects actually built. I know policy will be following on later, but just some topics to think about, firm ancillary service markets, you know, we need long term buyers. It's hard to build a 20 or 50-year asset on a five-minute market. We need storage tax credits and incentives for developing storage projects, including in the RPS, certainly perhaps AB 2514 is a step towards that and we look forward to working with both the Energy Commission and the PUC on those issues, and believe that pump storage, along with the other storage technologies can help us toward moving toward a more carbon-free electric generation market.

MR. GRAVELY: In the interest of time here, thank you very much, we have time for one or two questions in the audience. Does anybody here have any questions? Come to the mic, please.

MR. CUTTER: I have a quick question -- Eric Cutter, E3 -- on whether all the new hydro facilities are sort of automatically adjustable speed drives, or if there is a cost benefit tradeoff you're looking at in terms of incremental regulation and that kind of revenue to make the extra cost, adjustable speed.

MR. DIVINE: I think projects that are currently being looked at in the U.S. typically will have maybe some adjustable speed and some synchronous speed in a single facility. I know that a number of the projects in Europe, they're either adding adjustable speed to an existing facility, or they're looking at, again, adding maybe a 2+2 configuration, you can get a lot of the benefits of adjustable speed with not making the whole unit adjustable speed.

MR. GRAVELY: I'd like to add one thing here. We haven't talked about it, and of course, this technology with the length of storage, as we knew about the night time wind here in California, that could be an issue in the future, so, as we talk between now and next summer, or next spring, we do want to look at this load shifting. And some storage technologies like this one have inherently, you know, 6, 10, 12, 15 hours, some storages have 15 minutes to a half an hour with different applications, so we do want to look at those, so where it is not specifically grid support, it is specifically renewable integration. So, we do want to address and talk about that, and maybe later try and see what the value of that when you look at a project that has both, you know, how you equate the value both, for instance, if it's just one or the other. Thank you very much. So, hopefully those on line, using two mics is more helpful than just one, we're trying. Now, I'd like to turn it over to another technology that we're going to talk about again, this one here is one of the results of the ARRA funding, and we've talked about a single large project, so now we're going to talk about a distributed project, or a project that takes lots of distributed energy and controls it as one large project. So, Frank Ramirez from ICE Energy is now going to give us a presentation on how we can take distributed resources and turn them into a one single controlled grid resource.

MR. RAMIREZ: Thank you very much. We're really happy to be here today and for a number of reasons. In the first place, we are the redheaded stepchild, we don't appear in many of the graphs that you've seen because, while a very powerful storage technology we are, we don't store electrons, we store energy. And we store energy and produce work directly, and do so with round trip efficiencies of 1:1 or better at the site. As an electro thermal technology, we are unusual in this space, and we are purpose built to do but one thing, and one thing alone. Before we get started, I wanted to thank so many of you in the audience that are really responsible for our being here today – KEMA, EPRI, E3, and many of the members of the California Energy Commission and Public Utilities Commission who, over the last eight years, have sponsored our work. We are here today $100 million in the red, having devoted a great deal of time, energy and resources, to bring forward this resource that is now ready for prime time. That resource is the Ice Bear pictured before you, is in fact the technology that Art Rosenfeld referred to as the one technology that does not game the system, that creates value based on its ability to shift energy consumption on a permanent basis, leveraging whatever resources are available during off-peak periods, and offsetting but one need, and that is the need for air-conditioning comfort.

Our purpose today is to discuss what our features are, but I think when you take a look at the projects that we've done, you'll see that we are proven reliable, cost-effective, Smart Grid enabled, and that we're ready for large scale deployment today. Our benefits are not dissimilar to the benefits that are provided by electrical storage resources, or electrochemical resources, but given the nature and the highly distributed nature of our technology, we're also a driver of hundreds of California jobs. As a proven technology that is commercially available, we've accumulated more than 5 million hours of field collected data and operational run time. We've been piloted by 24 utilities over a seven-year period, we have an advanced manufacturing plant in Hammondsport, New York. We are executing today on a 53 megawatt utility scale contract with SCPPA, and we've structured some extraordinary partnerships in the industry, including those with OSI soft PI, AT&T's 3G network, Trane, and Carrier, who are now producing off of their production lines ICE ready rooftop units that quick connect to our energy storage modules. The benefits of distributed energy storage are such that, while we typically think in terms of only capacity and energy, the many benefits that can be imputed to storage are typically not easily modeled and are handled by the models that typically evaluate system resources. And for that reason, we partnered with R.W. Beck and released in October a new electric utility modeling guide that provides a mechanism and a how-to manual for system resource planners, total resource cost analysts, and integrated resource professionals, to be able to evaluate the various attributes of distributed storage, and those many benefits are captured here before you. Suffice to say that existing models don't do a good job at all of capturing value, and so many times when we work with utilities, we're forced into a situation where we're working inside of a particular silo, and what we've had to learn is how to work in an integrative way across the silos, in order to be able to bring different groups within a utility to attribute the various levels of value that, in the aggregate, provide a strong economic support for distributed storage.

I mentioned that we are purpose built for but one purpose, and that purpose is to reduce air-conditioning load for six hours a day, every day, by complementing existing energy removing resources that sit on commercial and light industrial rooftops. As you can see from the slide before you, cooling is about one-half of the commercial load and commercial air-conditioning load extends beyond the utility peak period. We've heard today that the value of storage increases as it is moved along the delivery chain of energy. There are various storage technologies that have a role, depending on where storage is placed, central, or pumped hydro at a central level, at a substation level a number of different technologies, including flywheels. At the very edge of the grid, we provide through phase change a storage technology that removes from the grid for six hours a day three phase inductive load on a permanent basis.

The graph before you is relatively self-evident, but for those of you who have not seen this particular presentation, we know that, and it is well understood that, the entire electrical system is thermally inefficient. During the heat of the day, before you pictured is a representative case in Los Angeles, where it takes 140 megawatts of generating load to deliver a generating capacity, in order to deliver 100 megawatts of effective work at the site. Those losses, those Exergy losses, are a function of grid adjustment losses, off-peak generation and adjustments, reserved margin requirements, all of them that are just losses in heat and thermal inefficiencies associated with getting electricity from the point of generation to the point where it is used.

Every two years, the California Energy Commission publishes a comparative cost of central station electric generation, and we've taken the data from this to plot two important points on a graph that can best be looked at as variable and fixed costs. On the upper left-hand corner is a simple-cycle peaker, on the lower right-hand corner is a conventional combined cycle plant. But bifurcating those two points is a line that can be referred to as a grid parity, or an efficient gas frontier, which essentially says that anything inside of that frontier is cost-effective, anything outside is not cost-effective. For purposes of this particular presentation, our particular resource has been placed on a relative benefit basis through a methodology that has been validated by E3. The simple conclusion is that we are cost-effective today without subsidy. But in addition to the energy and capacity, which was captured in the previous graph, little known is the degradation curve for HVAC compressor efficiency. Paralleling the efficiency that degrades in the performance of a traditional gas plant where nameplate capacity degrades as a function of heat, so too does a conventional air-conditioner degrade as a function of heat. Energy demand increases to maintain cooling and comfort. So, you get a double whack to the system. At the hottest parts of the day, not only do your generating resources degrade in efficiency, the very cooling resources that sit on top of buildings are degrading at a level that is almost comparable. Conversely, when we deploy our technology, our ability to cool a building doesn't vary as a function of heat. Running a continuous 300 watts of energy to cool a building with our stored energy in effect provides a resource that remains stable as temperatures rise, the net effect of which is that, unlike a generator that degrades in efficacy as temperatures rise, our equivalent output to the system increases as a function of temperature. Our effective benefit to the system, then, on a 100 megawatt deployment is the equivalent of 115 megawatts of benefit with what a 15 or 20 degree rise in temperature.

Today we are executing on a project in Southern California with SCPPA. As many of you know, it's a joint powers authority with 11 municipal utilities and one irrigation district. Today, we are executing on a 53-megawatt project on what is the first phase of what we expected to be a multi-hundred megawatt deployment of our distributed resource.

Before you are a number of applications, we've deployed approximately 200 units against this particular engagement at this point in time, and expect to eventually deploy as many as 6,000 units. As you can see, there are some ground bounded opportunities for fast food, for box retailers on the roof, fast food franchises. These units mount directly on the roof in rooftop applications near or within 150 feet of conventional RTUs. We've just done an 11-unit deployment on a Federal building on a new construction. But our energy storage module is far more than just the Ice Bear, what makes it a utility scale resource is the number one rated Smart Grid communications platform in the world. The Ice Bear, in conjunction with its embedded real time control platform provides a cost-effective, scalable resource that provides bulk storage in a distributed manner, not central, but distributed. The picture before you is one of the outputs that we provided to the utility, that enables the utility to configure how it gets the output from these many distributed resources. The control dashboard provided to the utility allows control measurement verification and customer defined reporting for the utilities. It organizes and summarizes the results as needed with the flexible navigation pane, and it's organized by area substation theatre, or building level data. The resources also tie directly into utility operations providing dispatch and control. Scheduled changes can be made on the fly in response to changing system conditions, and we can apply different control strategies to one or any or all a subset of other storage devices. Recent highlights include a CSI grant of Sun plus Ice, together with sun power target ice energy in KEMA and Sandia Labs. And I'll call attention also to a first energy project with EPRI that we're doing, a Smart Grid project in conjunction with Staples in Howell, New Jersey.

Today, we have relatively significant opportunities that we are in contract to conclude with Ontario Power Authority, with American Electric Power, with Tucson Electric Power, and with the Southern companies. We are today proven, ready, cost-effective, and moving into the market.

We also create a lot of jobs. A 100 megawatt project generates approximately 300 direct jobs, paying hourly wages in excess of $60 million associated with the building of these units, their installation, and their commissioning. The various types of green collar jobs that are created are depicted on the slide, and provide in many instances economic multipliers locally of between four and seven times. We'll argue that these jobs can and should be in California.

Barriers with respect to our adoption - we'll be providing written comments, these are high level comments with respect to the barriers that we see, that are true not only for us, but for all storage technologies, in general.

The lack of generally agreed upon cost-effective methodology probably is tops among them. There are a lot of regulatory regimes that don't yet fully consider storage, and there are numerous externalities of environmental and other conditions that are not captured, carbon being one, in terms of the value that storage provides at a system level.

In summary, we request that the distributed energy storage be included by the Energy Commission in the IEPR and other relevant policy proceedings as a valuable utility scale, cost-effective, renewables integrating, commercially available resource. Thank you for your time.

MR. GRAVELY: Time for one or two questions.

MS. PEITTE: Mary Ann Peitte, Lawrence Berkeley National Lab. Quick question about daily peak load management and permanent load shifting vs. dispatchability, if you could comment a little bit about that.

MR. RAMIREZ: The value that we provide to a utility enables the utility to dispatch and control our technology as they wish, it's been our finding and it's been the conclusion of the utility, that their greatest benefit inures from having us perform every single day permanently shifting six hours of load; however, from the control module that is embedded in our unit, we can also provide the opportunity to offset other compressors for 15, 30 minutes, or 45 minutes, allowing a control, even while they're permanently shifting the load that we provide. The embedded controller provides the opportunity for the utility to dispatch and control other rotating pieces of equipment on a building that they may wish to manage on a real-time basis. While we provide them with the functionality to be able to control each unit individually, it’s been our experience that their choice is instead to remove load permanently for six hours every day, during a period that absolutely covers their peak.

MR. WATSON: Dave Watson, Lawrence Berkeley Lab. Can you comment on the baselines methodology and the Measurement and Verification of this resource?

MR. RAMIREZ: Can you give me a little better explanation of your question?

MR. WATSON: Well, in order to evaluate a resource, you have to measure it and are you typically adding additional sub-metering? Or are you using existing whole building electric meters to measure the difference between what it would have been if your device was not installed vs. when it is installed, and when it’s dispatched vs. when it is not dispatched.

MR. RAMIREZ: Terrific. What we provide to the utility is verification that the compressor to which we are connected isn’t run. We connect to the first stage compressor in a rooftop air-conditioner. And the verification that we provide to the utility is that that compressor hasn't run. And depending upon the service territory, each compressor has value of between 6 and 8 kilowatts that are not being consumed during that time period, and our verification to them is that simple, that compressor hasn't run.

MR. GRAVELY: I would like to point out, just for purposes of today's discussion here – Frank, thank you very much for the presentation – we hear the phrase "virtual power plant," I think we've just seen a discussion of a virtual power plant. I think the elements that they have worked out, the logistics, the communications, and as Dave Watson brought up, the verification process, is very critical, it is a fact that we can have thousands of distributed systems that can be managed by a single control system, and you can verify what they do and don't do, it brings a new opportunity for us to consider as we go forward in the area of distributed resources.

So now I'd like to turn it over to Janice Lin from the California Energy Storage Alliance, who has been very aggressively helping California and was very involved in AB 2514, and represents many of the people here, as well as other storage agencies throughout the country in trying to advance energy storage in California.

MS. LIN: Thanks, Mike. Hi, I would like to thank the Commission and Mike and Avtar for inviting me to be here today, it is really great to be back up in Sacramento. Let’s see here, so Mike and Avtar asked me to talk about the importance of energy storage to California’s renewable future. First a little bit of context. CESA, as we’re called, it’s the other CESA, California Energy Storage Alliance, we were founded in January of 2009, and our mission as an organization is to expand the role of storage technology to accelerate the adoption of renewables in a clear, more affordable, and reliable electric power system in California. We started out a few months ago with just a couple of members, we’re up to 28, and a couple more points about CESA, we are technology neutral, so we represent just about every storage technology. We are Agnostic as to type of technology, we support all ownership models, and of course, our focus is California.

One of the great things about being later in the day is you present slides that everybody has already presented. Here is a familiar chart that has been presented at least a couple of times. What I did want to emphasize is that there are many types of energy storage, and how we look at the world of energy storage, it does include thermal, which is this nice little gray overlay here on the top. Because many folks, as we kind of go out in the world, you know, sort of approach me and say, “Well, isn’t storage just in R&D? I mean, what else is there besides pumped hydro?" Well, for starters, there is a lot of storage in the world, like upwards of 125 gigawatts, more than 125 gigawatts installed worldwide. Now, granted, most of that is pumped hydro, and we love pumped hydro, soon you guys have to join our membership, but there is at least several thousand megawatts of other types of storage installed and operating commercially today. And rather than spend a lot of time because I only have 20 minutes, I just wanted to show you a few pictures, some technologies here, you saw the Ice Bear, Frank had a wonderful presentation. Down here in the lower left corner is a Beacon flywheel, this is a three-megawatt installation, but they have 20 megawatt installations under construction now in the Northeast and the Midwest. Up here in the right-hand corner is a 34-megawatt battery integrated at a wind farm in Japan, a sodium sulfur battery, and there are several examples of lithium-ion technologies. And down here in the left-hand corner is a one megawatt hour battery from Extreme Power that is integrated with wind on the island of Maui.

Okay, so some of the drivers of storage, I don't want to spend a lot of time, but it's important for context that we understand there are many drivers of storage. Renewable integration is one of them, and I understand that is the focus of today, but we also – it's important to remember that storage is a very key asset and a fundamental part of the Smart Grid, and we have our inexorable peak load growth and transmission constraints especially here in California. Another key driver is that storage will reduce GHG emissions, and I think it has been spoken about, and Frank covered it, but what you show here on the chart is the brown line is the emissions, this is tons of CO_2 per megawatt hour of peaker plants, the aqua line is the sort of base load combined cycle, and the idea is you can shift mode from peak to off-peak in well-cleaned air. Okay, very funny font, sorry about that. Here's a MAC/PC conversion.

So, shifting over to the benefits of California, there are four benefits that we like to talk about really big picture, one is that storage deployed in California will create jobs for California, and I think Frank covered that with some examples of job creation. There is a project in a factory that has been announced, that is being built in Southern California and LADWP territory. LADWP is also installing through that same partner, it is a Chinese company called BYD, have five or 10 megawatts, four-hour system, to integrate with our wind farm out near Tehachapi. So that is job creation happening right now; 2) energy storage does support California's landmark AB 32 legislation 3) energy storage will help enable our achieving our Renewable Portfolio Standard; and 4) as I mentioned earlier, it is a key component of our Smart Grid goals. One of the challenges and barriers that energy storage and I think it was Dave Hawkins who mentioned earlier, that for the gentleman from Southern California Edison, that the policy is so important in thinking about the applications of storage, but it’s really the policy and what we focused on is what determines how it will be deployed in the market. And you know, as an advocacy group, it was a perennial frustration of ours that storage is relevant in so many areas, in just about every area, just pick one, but yet there was no focus, it wasn’t the top one, two, or three priority from any one group, in any one of those silos. And fortunately, we’re very thankful to have Jerry Brown and Nancy Skinner’s leadership, we now have AB 2514, so we’re very excited about the leadership and the focus that that will bring across the many different policy areas in California.

So, I thought it was worthwhile to spend a little bit of time talking about AB 2514. There has been some misconceptions about it, but it passed, it was just signed into law on September 29th, and this would establish procurement targets for 2015 and 2020, and for the POUs, 2016 and 2021, respectively. And some key things that folks are a little confused about, one, it is technology neutral, so any of those technologies that I mentioned above, would qualify towards meeting the goals in this bill, however, the technologies have to be commercial and they have to be cost-effective. Secondly, the bill is also ownership neutral, so the assets could be rate-based, it could be procured from a third-party, it could be customer owned and procured. And any of those models work towards satisfying the procurement requirement. And finally, electrical corporations with less than 60,000 customers are exempt. So, that's all I have to say about that.

There have been a lot of discussion today about the many value streams that storage provides, and you know, one of our challenges has been the policy and regulatory focus. The other challenge has been how you align the many benefits to the purchaser of the equipment, and it's our hypothesis that, through that regulatory focus, we can remove the market barriers, align the existing benefits with the existing costs, and we will see cost-effective systems be deployed and be deployed rather quickly. So that's why we say government intervention is needed to align those benefits with the cost.

Because today is about renewable integration, I wanted to talk a bit about some of the applications for storage for renewable integration, and I'll go quickly because many of them have been addressed today. The first is a cleaner, more effective alternative for frequency regulation, 2) storing renewable over-generation, 3) assisting with renewable generation smoothing, or shaping, and the fourth is generation shifting, so literally taking bulk generation, and I think the gentleman from Eagle Crest addressed that very well, as well as ramping.

This is a chart that has been presented many times, and it’s based on some work that CAISO did in ’07, to estimate the increased need for regulation and also ramping as we achieve different RPS standards, and I think Dave already covered this a lot. The bottom line is we’re going to need more regulation. What’s really cool, and this is another view of some of the same data that Dave Hawkins presented, is that storage, and in particular, fast storage, is more capable of following a faster, frequently changing regulation signal than traditional resources, and the traditional source that’s provided this service is fossil generation. What you see on the left is the command from, say, the System Operator, and this is the response from the generator output, you can see it’s kind of slow, it’s not really matching that signal. In the flywheel example, this is real data, I believe it was, whereas this is in PJM territory, what it shows is you cannot even see the difference between the pink and the green line because they are so closely matched. And the idea is, when you have a resource that can meet your needs so accurately, a couple of great things happen, a) you need to buy less of it, so that is where some of the savings and some of the benefits come from, and 2) this resource just tends to produce less emissions, it is super efficient and there is no on-site emissions. So a KEMA study from January of 2008 showed that, looking at 20 megawatts of regulation over a 20-year operating life, that storage actually dramatically lowers CO_2 emissions, as compared to some of the other sources.

Another way that storage can help with achieving our renewable portfolio standard is, when you look in time, now, this is not the case today, and I'd like to thank Eric Cutter and the folks at E3 for this analysis, it was just presented last Wednesday at the Permanent Load Shifting Workshop, but through E3's work, they did some scenarios and said, well, you know, in 2020 when we have a lot of wind on the system, and they modeled in this case almost 9,000 megawatts, what is going to happen? And what you see here is that the wind generation sort of exceeds the must run net loads, so this is a synchronous wind power and this is the over-generation. And the idea is that, if we had storage installed at that time, we wouldn't need to curtail that valuable clean renewable energy.

Another application of storage is what we call smoothing and this is an actual output chart of a Vanadium Redox flow battery in Japan. This system was installed many years ago, it's Tomamae wind farm, I think it is in Hokkaido, and what this shows is you have the blue line here, this is the charge/discharge function of the battery in response to the wind production, which is this green line, and then what you see, the net line is this red line, it is moving much smoother. And because Hokkaido is an island of crude systems, really fragile, they much prefer to see output that looks like the red line than the green line.

I would like to switch gears a little bit and talk about how storage can be used system-wide, and this is just a what if scenario, I think I represented this here a couple years ago, and the idea is that we don't necessarily need -- large pumped hydro plants are great, we need those in our system, but you can accomplish a lot even with very small storage systems that can be cost-effectively deployed today. This is a what if scenario that EPRI put together some years ago, that shows a day in the life of CAISO. And this dotted black line shows the typical summer daily demand, this blue line shows what the demand would look like post- the CSI implementation, so imagine if there are 3000 megawatts of solar put in on the system, and this resulting red line is a what if – what if we put in five kilowatt hours of storage for each KW of solar – it was arbitrarily chose, but the net result is quite dramatic, you see this peak is dramatically clipped and you have more demand at night. Okay, while we're on peak, I know that earlier, the gentleman from Edison talked about the Chino project which was a 10 megawatt, four-hour lead acid system that was installed and operated in Edison's service territory from 1988 to 1996, quite successfully, and I often hear people say, "Well, we closed it down because it met its research objectives and it wasn't cost-effective." But then, when you ask people involved in the project, "Well, how did you define cost-effective, because we don't have a cost-effectiveness methodology for storage today," the answer that I was told was, "Well, we looked at the capital cost of the equipment and we divided it by the difference between the peak and the off-peak, and it was a really long time. And that's certainly one way of looking at cost-effectiveness, but we would like to offer another perspective, so a couple months ago, we authored a White Paper looking at the cost-effectiveness of storage, and decided to model lead acid in that application since we had a successful demo, lead acid is commercially mature, you can buy them today, and we said, "Well, what if? What if we built that plant? And instead of 10 megawatts, let's make it 15 megawatts. And what if we built that, instead of building a 15 megawatt gas-fired peaker?" And what this chart shows is that using very conservative assumptions of what lead acid would be installed for today and, again, this is not a sales commercial for lead acid because we represent all technologies, but it's just an example, if you use the same methodology that the CEC uses for comparative cost of generation, which looks at dollars per megawatt hour discharged per year for a 20-year horizon, or dollars per KW per year, so the same use cycle, side by side, centralized plant, centralized storage plant, the storage was cheaper! Now, I actually was a little surprised, I was expecting it to be a little more expensive, but in this case, it was downright cheaper. And the beauty about the storage is you don't have to build a 50 megawatt battery, you can sprinkle it around and put it where you need it the most. Okay, Mike is looking at his watch, I'm going to hurry up.

These are all the assumptions, the case studies on the website, including the spreadsheet model, I invite you all to take a look at it. The other great thing about storage is, there's no on-site emissions and what we did was we assumed charging the battery with PG&E's energy mix, delivered air quality savings of 55 percent in terms of CO_2, 85 percent in terms of NO_x, 96 percent in terms of NO_x and SO_x, it was tremendous. So I encourage everyone to take a look at that and think about the cost-effectiveness of storage a little differently.

So, switching gears yet again, there is a lot happening, one minute, I'm wrapping up. As I mentioned earlier, storage is fundamental to many energy policy initiatives here in California and thanks to all of you, we are in some ways the leaders in thinking about grid storage, nationally. We have the right foundational legislation, we have this fabulous integrated IEPR planning process, we have very active regulatory implementation at the PUC across a number of areas, and we have a lot of activity at CAISO, and what we need, and what I'm asking for at the CEC and all the agencies involved in our energy policy framework here in California, is we need a little more leadership, more leadership to leverage storage's many strengths across all these areas, more leadership and coordination. So, we like to think about the system not only in terms of supply and demand, transmission and distribution, but also in terms of system optimization that can be accomplished with energy storage.

Finally, we have some thoughts and ideas and we will be filing comments, written comments, but there are some specific ideas for how the CEC can accelerate progress, 1) we have a wonderful Smart Grid vision for 2020, we need a vision for storage that is focused on storage and its many applications across the system, 2) keep up the good work with PIER R&D Plan, 3) to support incentives to encourage utility procurement of energy storage capacity and services, 4) encourage the CAISO to implement that tariff, especially for regulation energy management, 5) the CEC's activity in siting new power plants and new T&D can be a really key gaiting factor to make sure that, as we do that, is there a cheaper alternative, could that same function or goal be accomplished another way with storage? And last but not least, we have a recommendation to add storage to the loading order and potentially consider starting energy storage collaborative similar to how you've done wind and other renewables. Thank you.

MR. GRAVELY: Thank you, Janice. So we still seem to be having mic problems here. I think we'll work on that over the lunch if you can from there. Any questions real quick, one question from anybody for Janice? Okay, this is the last presentation before lunch, and so we've heard from both the PUC and SCE about the A123 system going in Tehachapi at 32 megawatt hours, and we will hear the specifics from Charlie.

MR. VARTANIAN: Thank you, Mike. And thank you for the opportunity to speak and to join a really great panel, providing both a range of backgrounds and perspectives. I would like to say that A123 is a very satisfied member of CESA, I think they gave a really good hit on some topics I would have otherwise hit, so I'm going to stick to some of the technology at hand at A123 specifically is bringing, but I would also like to offer up that it generalizes to a number of advance technologies, and I will say legacy technologies discussed today that are expanding their capabilities. So, part of my – to frame my discussion, message 1, storage is not new to the energy system, but within the last 10 years, there have been significant technical and commercial breakthroughs, major incremental progress that make the technology relevant to applications where it would otherwise have not been considered even three or four years ago, and we're a good example of that; 2) so I would say, as an asset class, storage shares that across the spectrum, we have a diversity of capabilities from very fast to very long where advances have been made, and 3) another shared attribute we have is – I'll put forward my opinion – regulatory evolution is a number one need, that we are technically credible and commercially credible today for a range of what we can access as niche services. We can definitely provide more benefit with a little bit of regulatory evolution work similar to the technology. California is at the forefront somewhat, maybe not at California's prompting, but leaps, for example, in that FERC case, Western Grid Developers is at least bringing storage into the discussion of the cost recovery mechanism from that wholesale angle. So, what are we doing? A123 Systems builds lithium-ion batteries and battery-based systems using – I want to point out one cathode chemistry – nanophosphate.

That one chemistry provides such incremental leaps in capability that we're not worrying about other chemistries, we're just packaging a single cathode from 25 kilowatt, 50 kilowatt systems, to an in construction 20 megawatt, 15 megawatt system, once again, it scales out farther, there is no limitation on our architecture, the system level will go to 200 megawatts, and it didn't get a lot of attention, but we did have a highly rated proposal for a 100 megawatt system in PJM as part of the DOE Stimulus funding.

So we do this in the U.S., using nanophosphate chemistries, manufacture components in China and the U.S., but systems for the grid are built in Hopkin, Massachusetts. So, we are one example within the storage community of massive gains and capabilities. And this is driven – for us, what is very convenient, it is one attribute, it is a high contact area within the cathode, translates to low impedance. What does that mean at a battery level? That means that the battery has over 98 percent round trip DC efficiency. You would not have a battery-based system doing frequency regulation with a 95 percent capacity factor continually exchanging energy, but for a battery that gave you 98 percent of all the energy you put in back out. That lower internal impedance also means very low heat, so the degradation mechanics that otherwise destroy batteries, they're still present, but they're extremely slowed down and they're highly linear. So, once again, even on a highly intensive utilization, like frequency regulation, the need to refresh, add capacity, to maintain a system rating, we're talking years, not months or days. Even at a full depth of discharge, if you were to do it – use it for diurnal, let's say, shift – energy shift – 10,000 round trip, full depth of discharge, once again, these are quantum leaps at the technology level that the market, the users, are starting to access.

This will be posted, but once again, it comes down to life durations that were unheard of before ours and other advance electro-chemistries have come into play, very high round trip efficiencies, combine that with the new efficiencies and the robustness of megawatt scale inverters, and here is a key element, and I love to see the ISO in the audience, and the utilities, you have a four-quadrant unified power flow controller that is going to be a very important grid asset, forget about all the market crap, it'll do its job there, it's commercial today in that market, as a grid asset. And one of my goals is to bring the ISO planners and the utility planners a WECC accepted model that they can run and a dynamic simulation to show it's bringing these abilities to bear for transmission solutions. So there are some pictures. One of our methods, once again, concentrate on a single chemistry spread across a number of not just power applications, but market segments, the same cells being built for automotive are the ones we're using within the Grid. And I will state A123's viewpoint, what we're doing with Edison and Detroit Edison for demonstrations, the DOE demonstrations co-funded here in California for Tehachapi, isn't a proof of the battery, we have a million miles accumulated on that same exact battery chemistry happening today, two years in service, hybrid busses in San Francisco, the cells work, we have no lack of confidence that that'll be proven out, that isn't want we're hoping to prove, it's the applications, putting into its system that does something useful for the Grid. This went out in 2008 with a client, AES storage, that used it as a test system. Could it receive an AGC signal and respond? The shorter answer is yes. Could it follow it accurately? Yes. Could it respond quickly? Within 20 milliseconds, its stated ramp rate in its certification testing and tested again, so it was 999 megawatts per minute, and that's because those were the figures available within the form. Once again, Pacific Northwest National Labs is really doing topnotch work, and KEMA has and continues on quantifying – what is the value of speed? And it translates into a lower amount of capacity needed. I will just say this, we have a client that has approaching 36 megawatts of capacity in various markets, no tax incentives, no government underwriting, with commercial payback, selling frequency regulation and spending reserve with a battery-based system. So, if you have any conceptions or, even based on the research that is out and present today, what we're actually doing in the real world in a number of markets might surprise you in terms of what we're delivering commercially. Feel free to ask me outside of this. There are some notional pricing points I am comfortable sharing that are out in the public.

So, we are going to extend our early experience and I'd like to touch on Smart Grid. Smart Grid does one great thing, it brings interoperability as a requirement, which makes it easy for the receivers, utilities can understand. All I am are power injection, power absorption, VAR injection, VAR absorption, either responding to a dispatcher, a schedule. A transmission planner or a distribution engineer really isn't going to delve into my chemistry, so I want to present a device that is understandable to them in their context. The Smart Grid, that the whole encompassing effort, really makes that possible, gets us talking the same language with the Grid people, please have spoken really well in terms of characterizing the renewable integration challenge and opportunity. We are really lucky to team with Southern California Edison, who has a Grid asset at the right place, with the right challenges, against which we will team to show that advance batteries can bring a number of capabilities of relevance, and what I want to point out is, as the vendor, A123 didn't bring the list of functionalities that we're going to demonstrate here, it came from the utility and the CAISO. The quick list, didn't know if it was going to be on the Edison slide or not: transmission related benefits, voltage support, grid stability, decreasing transmission loss, diminished congestion, optimized their renewable transmission investment, system level functionalities that we'll demonstrate, and this once again, in collaboration with the ISO, the utility, and the A123, provide system capacity, demonstrate renewable energy smoothing, demonstrate renewable energy shifting, and ISO/market applications, frequency regulations, spending reserve, ramping, energy arbitrage, people have spoken to the cost, I want to stick on that, go back to that, for a moment. Once again, I want to talk about what we're doing today that we can extend that for these applications. Twenty megawatts is being built in New York by AES Storage, average clearing price is north of thirty mills, our fully amortizing our capital cost in the O&M over the megawatt utilization is on the order of $20 mills, so, today, Charlie's opinion? Not cost-effective in the California ISO for that single value. But I'd like to put out, if we opened up and brought the black start value, the VAR value, other values, we start getting there. But, once again, out there commercially today, 20 megawatts under construction, we will take that same technology and extend it to these 13 applications, and I think Edison was wise in terms of, "We'll do it serially one at a time, but we'll also start answering what you can do coincidentally." And that's going to be a key aspect of the demonstration phase taking place mid-2012 through mid-2014, is the test phase.

Detroit Edison has a different – very different in terms of scope, 25 kilowatt community energy storage systems, 20 of them co-funded by the DOE, here I think the real value out of this is going to be the aggregation and talking to a utility in context of a single unit, and a fleet of units. So, ICE Energy, I think, is a real leader among our peer group, and we hope to catch up a little bit in our understanding of how do you actually accomplish this. There can be big power through aggregation, the Demand Response community, already is accessing and utilizing the power. I think we need a few post docs in math at A123 before we get our arms around aggregation. But, in the mean time, we'll learn with Detroit Edison, how do we at least execute that capability. Those are once again utility driven. They put the list of functionalities up and they basically left it to us to respond, can we deliver that capability or not, and I'll put it in these terms, we gave them a commercial quotation against those requested requirements. This is for California, in particular, because these scenarios exist here. And once again, slightly aimed at the ISO. I do intend to get ultimately WECC approved for formal transmission study, path rating studies, interconnection studies, a number of models, so they can start being incorporated and used, and I'd really love to hear that the Grid planning process is going to consider how it's going to integrate storage. Well, one way we could make it easier from the advocate side is bring them a model. I have the term "innovation fatigue" and when I talk to the planners, engineers, they've had enough, and the only time I get engagement is if I can explain how it helps them meet known problems, how do they deal with AB 32, SB 17, RPS accomplishment, and now, on top of that, AB 2514 compliance? They are really receptive when I talked about not storage as a new thing to deal with, but a new tool to meet what are basically approved challenges set before them. One way I think as a community we're going to do that – EPRI did this 20 years ago – I am using EPRI models today in an interconnection study, but it's a one off approval, and we can't do that effectively, we need storage models. And here we go, Phaser measurement units, I want to commend WECC, ISO, and Southern California Edison, who really was the champion in this. Phaser measurement units connected with every storage device is going to prevent future cascading outages within our area. The last cascading outage in 1996 was an under damped real power oscillation between us and the Pacific Northwest. Those same mechanics exist today, provide that same threat. That's Chino down on the left-hand corner responding to an inter-area frequency deviation, and showing that the GE energy storage power system stabilizer – you know, this was done 25 years ago, they had a power system stabilizer designed and built for a bi-directional energy storage device. Chino? They could do frequency damping. Our battery is completely technically capable of doing dynamic, inter-area frequency area damping, and I would say one megawatt doing frequency damping is a benefit, and it never hurts, you can get 100 megawatts doing dynamic frequency damping, you do start bringing the system back into compliance with what otherwise would have been an outage. Now, that's Charlie speaking, not A123, but I know that once we get the transmission planners, the models, they'll start seeing this aspect of benefit and it will help the T Investment Recovery argument. You know, storage, I think, is amplification-based in terms of how it should be monetized and the investment recovered, why box it "TDG" or "S"? I would say it depends on how you're using it and who is making the investment. Thank you.

MR. GRAVELY: Time for one or two questions. Any questions for Charlie? Okay –

MR. VARTARIAN: Lacking a question, can I use that one minute? To "asks" – get storage line item discretely in the loading order, and get it discretely dealt with in the IEPR as a stand-alone asset, not in context of efficiency or demand response, or even cars – it fits great there, but as a stand-alone element. Thank you.

MR. GRAVELY: Thank you, Charlie. So I thank all the morning speakers. We have a full agenda ahead, so we'll break now for lunch, and be back at 1:15. And hopefully we'll get the mics working a little better. As you might have learned, we heard they upgraded the system about a week ago, and we seem to be the sacrificial lamb for the WebEx. Thanks.

(Off the record at 12:17 p.m.)

(Back on the record at 1:20 p.m.)

MR. GRAVELY: So, for those of you back online again, this is Mike Gravely. We're starting the afternoon session and we're pleased to have our first speaker here. Robert Schainker is going to talk quite a bit about a couple of PG&E projects that EPRI is actively involved with. You heard from Chris this morning that the PUC had approved two projects, one of them was the SCE one, the second one is the compressed air project that PG&E is doing, and also, soon, we're hear how soon from Robert, PG&E will have the largest battery storage system in California operating sodium sulfur system, so we're going to hear about both of those today and I think PG&E is online, Eric and Kevin are online if there are questions at the end. With that, I'll turn it over to Robert Schainker.

MR. SCHAINKER: Great, thank you. Thank you very much, Mike. And of course, I am here representing PG&E as one of the members of their project team for both the compressed air project and the sodium sulfur battery project. Before getting into that, though, I wanted to specifically call out the fact that Mike Gravely is to be commended for getting all the right people in the right room at the right time, in fact, at the same time. And this effort to have this meeting took many months to prepare and orchestrated a lot of people in the process, so I wanted to personally thank Mike Gravely and his team of people for making this happen. So, thank you again, Mike.

With this introduction, let me go to the first slide here, and this sort of reminds everybody of that renewable mix for PG&E, for various years on the horizontal axis from 2005 up to 2020, and what you see is a very large growth in solar, which is the yellow, and a very large growth in wind, which is the lowest colored sort of a bluish color, and everything here is shown on a percentage basis by year. So, this sort of sets the stage for why energy storage or any other kind of rapidly ramping technology that can accommodate the power fluctuations from both solar and wind, it needs to be really demonstrated in a real world environment, not a simulated environment, a real world environment on a real utility, on a very good utility here in California, PG&E. This slide here has actually been shown a few times and there may be a few other slides in this deck that have been shown by others, which I didn't know until I came here, but this slide just reminds everybody – the orange is solar, the wind is green, and when you combine them together, ideally, they do levelize each other out to some extent, but on the shoulder are these huge ramping requirements that has already been talked about by the CAISO and other speakers here.

This slide 3 actually was prepared by EPRI and it's been used in many forums by others, which is fine, and shows in a long scale, on the horizontal axis in power, and on the time axis, the vertical axis, in time and duration, the various types of energy storage technologies. And, fortunately, some of the speakers have actually taken the log scale off, and I think I have that – no, I don't have that here – and when you see pumped hydro and compressed air in the tens of hundreds of megawatts, and even thousand megawatts scale, for long hours of storage, and you take away the logarithmic depiction on this slide, you'll see that, in fact, pumped hydro dominates the upper right-hand corner, and compressed air comes in very close behind that, and all these other technologies, in particular the flywheels and SMES, and the batteries and such, they are really very small contributors to the real bulk energy storage needs that the State of California requires. So, I'll talk a little bit about both compressed air storage and the sodium sulfur battery projects for PG&E now.

As indicated by me and others, but maybe not shown in this sort of simplified sort of mechanism chart that is on page 4, we have a lot of power fluctuations coming out of wind and solar, and if you had the proper storage technologies, NaS standing for sodium sulfur, CAES standing for Compressed Air Energy Storage, and we have the proper Smart Grid inputs, and the proper control algorithms, we should be able to levelize the net input to the grid in a dispatchable format for storage technologies and wind technologies taken together. Now, the resources needed to provide the various types of ancillary services are shown in this slide, number 5, and this is just really a few of the many ancillary services, in particular regulation is in the five-minute timeframe, and the load-following is in the intra-hour and hour ahead forecast timeframe, and what I would call arbitrage, or "buy low, sell high" kind of duty cycles for storage, is really in the day ahead timeframe. Before leaving the slide, I must say, the words "ancillary services," I think, is a misnomer because the word "ancillary" generally refers to things that are secondary or tertiary, and what we're going to find, in fact, it's been mentioned already, but I'm sure we will find it in the real world, that these ancillary services that the California grid needs are not secondary or tertiary; as more wind and solar come on the grid, they become a primary service that is required to keep the system at low cost, and to keep it stable, so we have to understand, as engineers and workers here in California, that the word "ancillary services" probably needs to be understood in a macro sense, rather than in a micro sense. It turns out, by the way, that in Europe, they don't even use this term, they don't use the term ancillary services at all. They use the term grid services, that is their analogue to the words "ancillary," and they keep on asking me when I go over there, why do we use this word "ancillary," and I said, "Well, somebody started using it and we're sort of stuck with it because it's in the laws now." In fact, I think the first laws that used that word were at FERC, the FERC rules about three or four or five years ago started off with that set of words, so we're stuck with those words. Slide 6 really talks about resource adequacy and some people refer to it as RA, but

Resource Adequacy, and there really is a mismatch between the actual real load and what the thermal and existing -- generally speaking -- existing generated units can supply. So, this just depicts the same kinds of things that some of the other speakers mentioned earlier.

Okay, now getting into the sodium sulfur project, what PG&E is going to be doing is that they've already purchased the battery, it is a four megawatt battery, it has an inverter that allows it to operate in all four quadrants, and what that means is it can charge and discharge in both a real and a reactive mapping of power that is needed by the Grid. And for those that have worked in complex number arithmetic where the square root of -1 is equal to "i" and we do all this imaginary number kind of calculations, I just want to ensure everybody that reactive power for charge and discharge, that batteries can produce is not imaginary, it is actually real, and it is just an arithmetic process used to calculate the phase angle between the sinusoid voltage waveform and the sinusoid current waveform, so this is, if you properly rate inverters for batteries, you don't rate them in megawatts, you rate them in MVA and that's really the hypotenuse of the triangle where the real axis is horizontal and the imaginary axis or the reactive axis is vertical. And this plant will have seven hours of storage, it is a sodium sulfur technology. The partners involved are certainly the California Energy Commission is co-sponsoring this project, EPRI is providing some assistance, NGK is the manufacturer of the sodium sulfur batteries, that is a company in Japan. They got most of their money from Tokyo Electric Power Company years ago to help develop this battery that actually was originally patented by Ford Motor Company, the sodium sulfur technology is a Ford Motor Company patent, but that patent has long since retired and many many companies have spent a lot of money trying to make sure the sodium sulfur technology works properly and the Japanese really did the finishing touches on that. S&C Electric is the turnkey contractor for the project, they are also providing the inverter for that project. The site is the Hitachi substation, it is a major industrial consumer of electricity on the PG&E system in San Jose, California, and I'll show you a picture of where this plant is going to be put. So, we've got support from the California Energy Commission, the California Public Utility Commission, as well as the Department of Energy for this project. We expect to have the battery operational in 2011, which is next year, and so there is a lot more work yet to be done. But the battery itself, as been purchased and is at PG&E now, it is not at the Hitachi site just yet, and the inverter is in the process of being built and all the other pieces of equipment are in the process of being put together by S&C. So, with the battery already available and here in the United States, we should be able to meet this deadline if all goes well. Page 8 indicates what it is going to look like, this is a picture of a sodium sulfur battery in the upper right-hand corner, and you'll see there are vertical modules, and each module is actually 500 kilowatts with seven hours of storage, and they slide out on shelves, basically, and then there's a separate small module for the ACDC AC inverter, and this picture indicates that this battery will get signals from the CAISO if all goes well, and we will actually operate it in frequency regulation mode, operate it based on our inputs from PG&E's database on wind power coming out of the Tehachapi Wind Farms.

The objective is to improve reliability, and particularly the voltage support at that particular site, load shape, smooth out the peaks and the valleys, and to optimize the grid at this PG&E substation area for renewables integration. We will look at Demand Response, black start, ancillary service duty cycles for this battery. This picture on the next slide shows a top level view – I think it is a Google shot of what the Hitachi facility looks like in the upper left-hand corner, and the actual big arrow shows a blow-up in the lower right-hand corner of the small section of the Hitachi facility, and in blue, on the far right of the lower right-hand corner picture, shows the power conditioning system, the AC/DC/AC inverter, the PCS as we call it, and then there will be two megawatt modules for this four megawatt facility. So, that's what it's going to look like and there is space available to site this and PG&E is going through all the necessary permitting and licensing issues associated with this installation as we speak. BESS stands for Battery Energy Storage System, and sodium sulfur is NaS, some people call this the NaS battery because, on the Periodic Chart, Sodium is a chemical that is represented by Na, and Sulfur is represented by the letter "s." So that's why it's called "NaS," if people hear that word, that is what they're referring to.

Now, on the compressed air storage project, this is a much larger project, it is a 300 megawatt 10-hour bulk energy storage facility, it is going to be sited in Central California on the southern part of the PG&E Grid near the Southern California Edison interface, and the partners in this project are the Department of Energy, which is providing about $25 million. As an awardee, PG&E is going to get $25 million from the ARRA funding pool, the American Recovery and Reinvestment Act of 2009, we can thank Obama's Administration for that money, and the California Energy Commission is also supporting this project. I think it is $1 million, EPRI is supporting the project with some time and money, and also some subcontracting work to PG&E to do the monitoring and performance analysis of the project, and we've got the California Public Utility Commission has already approved PG&E's Phase I cost for this project to be put into the rate base, and the project has got three phases, and we hope to get the whole project completed by the year 2017. The three phases of this project are shown in the left corner of this slide, number 11, and basically the first phase, which is starting to take off literally in the next week or so, once the final contract is signed, will be approximately two years, three years long, and is to do all the permitting, the geological studies needed for the porous rock media that is going to be used to store the air, and the transmission interconnection permits, etc. What you'll find is that Phase I will do everything necessary for PG&E to get to the point of issuing construction contracts, basically that is what defines Phase I, so we'll do a final design of the surface machinery, to match the underground geologic formation that is going to be used, which is still being investigated. And then, Phase II of the project is all about construction, and that's where the bulk of the money is going to be spent, to construct this 300 megawatt 10-hour facility, and then Phase III is a monitoring program, a monitoring and performance program, where PG&E has agreed with DOE that we're going to publish all -- appropriately analyze the data and publish the summary operational data of this facility. Page 12 is a map of portions of California, you'll see San Bernardino located here on this map, Kramer, the Tehachapi yellow area is where the wind farms are, the midway line is depicted as a major line coming off the midway substation of PG&E, and the plant is going to be sited somewhere in this neighborhood. I can't say anymore specifically right now because the rights to getting all the property locked up is still in the process of being determined; once all the geology studies are done, so we're very quiet about exactly where the plant will be sited. But this gives you a rough idea where it is, and you'll see Los Angeles is in the center, lower portion of this slide.

The operational performance of the compressed air technology, people may not be that familiar with it, but it is very interesting. It is a technology that, in fact, is not a pure energy storage technology, it has – it uses electricity for the compression process off the grid, and then it uses the compressed air that has been stored at night from the compression process, with some heat that is obtained from burning natural gas at about 4,000 Btu's per kilowatt hour, and together the electricity off-peak and the heat on-peak will produce one kilowatt hour of output energy. So, really, it's like a hybrid vehicle to some extent, it's a combination of pure storage technology and a generation technology all in one type of unit. For those that need more information about this technology, I would be happy to talk to you privately about how the whole thermodynamic cycle works, but it happens to be the second of such type of plant in the United States, the first one is shown in the upper right-hand corner of this slide number 13, and that's a picture of the Alabama Electric Co-op Plant that was built back in 1991, and the machinery is in this dark building that you see in that picture, and in the foreground of that little picture is a pipeline that connects the plant to the cavern, the air storage system for that site. Now, for the PG&E plant, we'll have multiple wellheads that are used to move the air in and out of the air storage facility, but it'll go into that plant. The plant design for PG&E will be an advanced plant design, utilizing the new turbo machinery since 1991, and a new thermodynamic cycle more than likely for the plant will be used. Of importance to this group is the lower bullet, the third bullet on this slide. This plant has approximately a plus or minus 40 percent ramp rate for 300 megawatts, so per minute you can get 120 megawatts a minute once it is synchronized, and it takes about seven minutes to get synchronized. And if you want to keep it online, synchronized with a little duct burner in the process, it can be available for that kind of ramp rate instantaneously, once it is kept online, and that's being analyzed as we speak, as well. So this is an amazingly fast bulk energy storage plant can provide tens of hours of storage, depending upon how big a bubble underground we make, and it has a very very fast ramp rate.

Okay, slide 14, it is a summary slide. I've just chatted, then, about the sodium sulfur project, four megawatts with seven hours of storage, and the compressed air plant with 300 megawatts with 10 hours of storage. And that's it. If there are any questions, I could entertain them now.

MR. GRAVELY: Any questions for Robert?

MR. SCHAINKER: Looks like Dave Hawkins is coming up to the microphone and he'll ask a good question, I'm sure.

MR. HAWKINS: On the compressed air energy storage, are you looking at a thermal storage capability to capture some of the heat out of the compression cycle?

MR. SCHAINKER: Very very good question. It turns out that this plant, as currently designed, will not be utilizing any of the waste heat in its generation cycle, however, this plant as currently proposed will provide an experimental base to capture some of the heat and compression and use it in a thermal storage facility on-site at full scale and a good scale, and so I am particularly interested in using this plant as a stepping stone, how many years it will take, I'm not so sure, to do the necessary homework needed in the field for thermal energy storage in such a way that a compressed air plant won't even use any fuel at all in the future. But to answer your question, no, this plant is not using the thermal storage coming off the compressed cycle, but it has the facility that we can capture and use that thermal energy to do some experiments. But, good question. Thank you, David. Any other questions?

MR. GRAVELY: Thank you, Robert.

MR. SCHAINKER: Good. Back to you.

MR. GRAVELY: Thank you very much, Robert. And, again, we're looking to California to have so many of these very good storage projects built and we'll get a chance to see some real progress over the years here. So, the next presenter we're having is from Pacific Northwest National Lab, Jeff Dagle is going to be speaking from WebEx, so maybe for one time, everybody on WebEx can hear him. Are you online? Can you hear me, Jeff?

MR. DAGLE: Yes, I can.

MR. GRAVELY: Okay, I'm going to have Patrick flip your slides for you, and you feel free to just let him know when you want to change, and speak, you've got 15 minutes, so thank you very much.

MR. DAGLE: Okay, thank you. Can we go to the next slide, please? So, I'm going to be providing two examples to talk about my topic area, the first example is a wet area energy storage concept, and this was a project that was done a couple of years ago, first with support from Bonneville Power Administration, and then the Phase II was a joint project between CEC and BPA, and the focus of the project was to study the combining energy storage with a shared frequency regulation service to provide AGC support to the Western Interconnection. One of the things that we're seeing with the increased penetration of wind energy resources is that the regulation services, the frequency of regulation services requirements are going up, and today that is being handled by our central generation plants, but we're seeing increased maintenance costs and wear and tear associated with those Governors needing to continue to respond to those signals. So I agree very much with the comments from the other talk, when Dr. Schainker talked about the requirements for a frequency regulation increasing, that is going to be, you know, we see that going very much in that direction in the future. So, there's a couple things at play here, one of the things that we're looking at with this project is sharing that regulation service between multiple bouncing authorities. If you notice on the diagram there, we've highlighted the California/Oregon Interchange, those particular transmission lines associated with that interchange, if they are at a constraint, then you're limited in terms of how you can share that regulation service, but most of those lines are not at their constraint and you can share that regulation service between multiple balancing authorities without having impact on the reliability of the bulk systems. So that is one aspect that's going on. The other aspect that is going on is taking the fast regulation and allowing the flywheel to implement that, and then backing that up with the hydro for the slower regulation service. So, if we can go to the next slide, through our modeled results here, what we've seen is that the overall concept can reduce the overall on a regulation reserve by 30 percent, and then, by allowing the flywheel to take the fast regulation, you minimize the wear and tear of your conventional regulating units, in this case we focused on the hydro in the Northwest. And then you let the various technologies sit with what they are good at, so the flywheel can do the fast regulation, and then the hydro-electric can support the flywheel through its slower regulation, but the key attribute there of working together is that you reduce the overall energy storage capacity needed by the flywheel, so you can keep the flywheel at a reasonable state of charge throughout its charging and discharging cycles, by re-dispatching the other frequency regulation services.

So, we focused in on BPA and CAISO as our test case and we looked at the existing signals from the AGC on generation control from those, and even though we focused on BPA and CAISO for our test study, we don’t see any reason why this couldn’t be used by the balancing authorities. Next slide, please. So, the current phase of the activity that we just wrapped up with the support from the California Energy Commission included a field test of a flywheel working in tandem with the signals coming from CAISO and BPA, and what we did is we had a 25 kilowatt hour, 100 kilowatt flywheel, that was responding to the signals so we can test and measure the ramp changes and that sort of thing with that field test. Go to the next slide, please.

So, the way that the test was set up is we had a regulation signal that then went to the control algorithm, and that was split between the flywheel and the hydro, and then the flywheel controller provided by Beacon Power was actually being dispatched based on that flywheel regulation signal, and then we can look at the combined results of that. Go to the next slide.

So, these are some test results and the top graph shows a combination of the hydro and the flywheel, to meet the overall regulation service, and then the bottom chart is showing the state of charge for the flywheel through a five-hour period, and so the hydro is basically being used to maintain that state of charge at a reasonable level. You might have noticed that the flywheel that was under test was a 25 kilowatt hour unit, what we were looking at was simulating a larger capacity group of flywheels, and so we were doing a field test with one of a simulated bank of multiple flywheels in this case, so the overall capability of the group was greater than the 25 kilowatts. If we go to the next slide, so the good news is that this concept seems to work pretty well, the hydro and the flywheel each respond in ways that are appropriate for the technology. We also see that combining the hydro with the flywheel reduces the cost of the scheme because you don't need as much energy storage in the flywheel if you can back it up with the hydro. But, unfortunately, the bad news of the study is that, at the current price of frequency regulation that we see in the Western Interconnection, in the CAISO it is about $12.00 a megawatt and BPA is even less, about $9.00 a megawatt for regulation, the actual cost for providing that regulation service doesn't quite meet our break-even price for the scheme, so it is still a little bit too expensive to implement today with the current cost regulations. So we'd have to see the cost of regulation services go above $12.00 a megawatt for this concept to make sense. And then if it's just the flywheel, that the hydro backing it up would be about $20.00 a megawatt.

So, with this study, and, again, it was a combined support by Bonneville and California Energy Commission, the flywheel response is relatively quick and it allows the hydro to provide the slow regulation, and while it looks like an effective technology, and the ramp rates are sufficient for doing what we want to do, it is still not quite cost-effective to provide this regulation based on today's price regulations. So, what we'd have to do is see the regulation price increase to have this technology be cost-effective.

So, what I'd like to do next is to move to my second case study, so if we go to the next slide, and I apologize, on my screen here, I'm seeing the title slide – or the title of my slide kind of wrapping out the edge there, but example 2 is the Dynamic Load Control Scheme to Stabilize the Transmission Network, and this is a project that we did a number of years ago, looking at basically the concept was could we have fast acting dynamic load control stabilize the electric power grid? It leverages a project that we did for EPRI in the mid-'90s, looking at the application of superconducting magnetic energy storage, that would be applied to the grid to stabilize the grid and provide transient support. And that study had participation from Bonneville, PG&E, Southern California Edison, Los Angeles Water and Power, and San Diego Gas & Electric, and looked at various locational aspects and control algorithms to provide the right kind of energy, both real and reactive power modulation, to stabilize the grid under a variety of scenarios. This study that I'm going to be briefing here on in a minute is extending beyond that study, looking at doing a similar type of thing, but instead of installing a storage device, could you get that same type of response through fast acting load controls through interruptible loads. So, basically a dynamic load control that would be attuned to provide this kind of stabilization.

So, the objective that we had for this case was increasing the imports in Southern California, and there is currently some stability constraint paths in there that are defined by the Southern California Port Transport Nomogram. And so, this particular case, you know, this was a number of years ago, so I was looking at the 1999 heavy summer case when this study was conducted. The control action, then, was we optimized to have the least amount of control action to provide an increase in the imports of power through that stability constrained path. And I looked at different assumptions for what the control points would be, what the feedback modulation would be, and then tradeoffs between real and reactive modulation. If we could go to the next slide, please?

So, to give you an idea of what this looks like, across that stability constrained path, the blue plot would be the response to the system at the stability limit, across that path for the critical contingency, and then the red plot represents what the same response would be if you increased it 50 megawatts beyond the limitation of the system, and so this is the approach that's used to identify what the critical limit is. If you go to the next slide, then what I do is increase the imports 400 megawatts beyond that, and then the red line there shows that is what the response would be without control, and then the difference between the purple line and the blue line is finding the minimum control, modulation control, that is needed to re-stabilize the system back to that critically damp case. Again, all of these results were conducted using the EPRI extended midterm transient stability program, which is equivalent software to the PSLF dynamics simulator, or the PSSE transient dynamic simulator.

So, on the next slide, the top is the modulation block diagram, modulation control block diagram, and that provides the compensated control for the modulation. The input signal was a variable that could explore different options, including local voltage, local frequency, or a global signal that would be sent out to all the controllers. What I concluded in the study is that frequency was a good input signal, and there was no real variation between global measured frequency vs. a local measure of frequency. That is the good news, that you can implement the scheme without any high-speed communication requirements, you can have an individual controller's modulating load using locally measured frequency as the input to the control block diagram there. So, you can take locally measured frequency, run that through, and then determine the right kind of gains and design constants, to get the properly formatted feedback control. And so, if you look at the bottom chart, that's a example where you would have 450 megawatts modulation and, given the constraint of that modulation, you know, it shows how that would respond to the cases that we're looking at in the previous slides.

So, the next slide shows some results. In order to provide that 400 megawatt increase in the transmission enhancement, if I do that at a single location, then I need 450 megawatts, plus or minus 450 megawatts worth of real power modulation, or plus or minus 500 MVAR of reactive power modulation. Those are the different options that are available. But one of the challenges with modulating load is, if you are curtailing interruptible load, you may not be able to do a full plus/minus megawatt of modulation like you would with a storage device, for example.

The next slide shows a series of case studies to explore whether you have a symmetric modulation vs. an asymmetric modulation, and so how you interpret this plot here is that, in order to get that 400 megawatts of modulation, you need 450 megawatts for the plus or minus, that is the blue square that is on that diagonal line, but you can also achieve that if you go to the far left with 600 megawatts worth of just curtailing loads, so it is providing a 600 megawatt injection and zero megawatts on the negative side, and so if you just have control over 600 megawatts of total controllable load, you can achieve that same result as the plus or minus 450. So, already you're starting to see a significant enhancement because plus or minus 450 is, you know, a total of 900 megawatts worth of modulation, total, is equivalent to zero to 600, so you start to see some gains if you just looked at doing a zero to a plus number.

And on the next slide, there is some additional advantage that you get by distributing that, so I took that one case study, or that one example, where it is zero to 600 megawatts, and that is at one key location, you can install at that location and modulate that level, and provide that stabilization, is equivalent to if you take 10 locations in the Southern California area, and you modulate those, the same result occurs when you have 44 megawatts each, so that is a total of 440 megawatts. So, there is some additional gain that you get when you take that modulation and you disperse it amongst the distributed load, as opposed to just doing it in one location. I repeated that study with the

100 sites vs. the 10 sites, and I got an equivalent number, roughly 440 megawatts. So there is kind of an asymptote that reaches there between one and 10.

And I already mentioned that local voltage and frequency had similar results, but one of the things that you need to watch out for with voltage is these particular transient models don't model the distribution system, they are basically aggregating all of the load at the substation, and then I'm applying my modulation controller, or my power injection at the substation. If you went to actually implement this in real life, there might be some issues with voltage, you know, depending on how that particular feeder is regulated and what the voltage regulation schemes might look like. However, frequency is still a valid signal because there is no difference between frequency at the wall plug vs. frequency at the substation. But then, the lingering issue is how to actually implement this.

So, on the next slide, what's happened since then is that the Department of Energy has provided support to research what we call the "grid friendly appliance technology," and it incorporates some of these concepts of frequency response of load, and this has been implemented in the Pacific Northwest Grid-wise test bed demonstration, and so we have some results of actually implementing frequency response of load at the demonstration scale where we have hundreds of appliances that are responding to grid frequency. And there is a larger Pacific Northwest Smart Grid demonstration project that is being funded through the ARRA grant on working with multiple utilities to implement more of these Demand Response technologies, and so that will be more results from that experiment coming up here in the near future. So, that is what I had prepared and hopefully I'm within the timeframe that you had allocated for me.

MR. GRAVELY: Very good. Any questions in here in the audience for Jeff? All right, well, thank you very much, Jeff.

MR. DAGLE: Okay, you're welcome.

MR. GRAVELY: We'll move on to the next speaker. And, actually, I was going to say here, for those who don't know it, Jim Parks is going to be teaching a class in proposal preparation after this is over. SMUD won a third, if not a half of the Smart Grid proposals in California. I think they have received the largest number and the largest amount of money. And fortunately, also for transition, part of the work they're going to be doing is using energy storage and automated Demand Response, so that will transition us from here into the Auto-DR, which is the last presentation for the day, so, with that, I'll turn it over to Jim.

MR. PARKS: Thank you, Mike. Yeah, we did on the

SGIG grant, I think we got 65 percent of the grant money that came to California. On the one hand, we were a little embarrassed, but on the other hand, we were quite elated. I want to talk a little bit about our storage projects here, so, you know, what's driving our interest. We have greenhouse gas regulations and we have renewable portfolio standards right now in California, it is 33 percent renewables by 2020. With the way the Legislature works, we wouldn't be surprised to see them say, "Hey, 50 percent renewables by some date down the road," and these renewables tend to be intermittent resources that are, you know, a little difficult for us to manage from a grid perspective. And these are things that I think you and the audience all know that. We also have a summer peak load where we need 400 megawatts for just 40 hours out of the year, and that's actually a significant issue for us, so we see things like energy storage and Demand Response as ways to overcome some of those issues that we have.

SMUD also has a goal that the Board established to reduce our greenhouse gas emissions by 90 percent by 2050. Now, if you're in the electric utility industry, you'll realize that that is a significant number if you have any fossil fuel generation at all, and we do, we have some natural gas plants, some co-generation plants, and so, for us to reach that goal, it creates what we call the energy gap, and I'll show a chart on that – I mean, not today, but I show a chart on it and it shows this wedge that is the energy gap, and people ask me, "Well, where are you going to get that? How are you going to fill that gap?" I don't know, but it's a big problem for us, so we see some of these opportunities that come from this. Solar has got a growing role for SMUD. If you look there at the chart, you'll see that in 2010, we have about 30-35 megawatts, and because of a feed-in tariff that we recently issued, and it was totally sold out the first day, we're looking at going up to like 170 megawatts of solar in the next three years, that's a huge growth. Now, for us, people think, "Oh, solar is great because it runs right across your peak." It's like, well, not really. Our peak is 6:00 p.m. on a super hot day and solar has ramped down significantly at that point in the day. And so it doesn't really help us from a peaking perspective. It does provide renewable generation, and that's great, but from a peaking perspective, it's a little bit lacking.

Wind, we have 105 megawatts of wind right now, or 102, sorry, we're going to install another 128 megawatts next year, so we'll be up to 230 megawatts of wind. If you look at the bottom chart there, you'll see the blue line shows the profile of the wind, and the red line shows our own load profile, and in general, what you can kind of see with that is that we're peaking when the wind is kind of ramping down, so here once again, we have another resource where we're going, "Okay, how is this going to fit into our grid? It's not really helping us in a peak situation." So we do have some opportunities here.

And here is our approach to energy storage. We're looking at both bulk storage and distributed storage. We're doing several projects with the Department of Energy and we're partnering with the CEC on many of those projects. We want to know how much we're going to put in, how much is it going to cost, what's it going to do, what are the benefits it's going to provide to the District, and so we're using a multi-pronged approach, so that we can develop an understanding of the technologies and determine the benefits to SMUD, and also you hear about things like cost-effectiveness, I mean, the latest numbers I've seen on, say, battery storage, for example, it's averaging something like $4.25 a watt, well, you know, we most recently built a combined cycle natural gas power plant and it was less than a dollar a watt, and so you start comparing this resource that we have, you know, 24 hours a day, seven days a week, vs. something that you have intermittently that may last 10 years if you're lucky. You start balancing those things and you go, wow, there is a cost for this type of control that we need in our system.

We're conducting several studies, and I'll go into some of those. I mean, it sounds like I'm speaking against storage, there is a place for storage. Right now, I see it as a niche place. If prices come down, or prices of energy go up, you're going to see that niche get larger over time. One of the things we're looking at, the biggest project from a storage perspective, is our 400 megawatt Iowa Hill Pumped Hydro Project, and you can see here, we're looking to put in this lake at the top of a hill, and this would provide us a variable flow, variable speed, hydro system that will generate – I've been told by the Manager of Energy Supply – that it will be over 400 megawatts, ultimately. Now, this isn't exactly an inexpensive technology, it can run up in the $2 to $2.25 per watt range, but it's still much cheaper than batteries and provides you with a lot more control. We see this as an opportunity to really control, you know, the wind resources, and to store the energy that we're getting from these intermittent resources, and then are able to control the flows to optimize our own system. This is the artist's rendition of what it will look like. Now, this project right now is in our Integrated Resource Plan and the Board is considering it, and I'm not going to tell you that we're absolutely building this project, but it's in a licensing process, our Board is considering it, it is a significant expense for a utility of our size, but when you look at our goals going out with the 90 percent reduction in greenhouse gases, the increased implementation of intermittent resources, this could be a very big project for SMUD.

Another thing we're looking at, at a subdivision called Anatolia, there's something like 280 homes with 2KW PVs so it's really dense PV, we're going to do three different projects at this location, one, we're going to go into homes and install storage systems in 15 homes, then we're going to go out and we're going to install larger storage systems at distribution substations, and then we're going to install a larger system at the regular system substation, and we're going to look at the impacts there and see if there are some ways to optimize the solar. So, in other words, as the solar is ramping down, the batteries can pick up that load. We see this as a really good project for us, and we're linked to the Energy Commission on that, and it is in an ARRA grant, also. This just shows how the communication is going to happen between the system and the inverters, and on the photovoltaic system.

The next project we're doing is two 500 KW range flow batteries, and one of them, we're going to put out at Anatolia, and that's one we're going to put out at the substation, the other one we're going to put on SMUD facilities, we have a micro-grid project going out there where we're going to have 300 KW, three 100 KW turbines, natural gas turbines, 10 KW of PV, and we're going to put the 500 KW batteries out there with six hours of capacity. And so, we're actually testing a switch on that one where these generators will be running and we're going to turn off the power to our central plant into an office facility we have out there, and then see if it's able to kick in time and the micro-grid, run the project off grid, as it were. We're sure hoping it's going to work because we like our central plant and we like the office, and the people in there like to have lights and air-conditioning and so forth. And absolutely, we expect it to work.

But we're working with the Energy Commission right now on two storage projects. This first one, I'm pretty excited about, plug-in electric vehicle grid impact study. You know, if you go out in Smart Grid sessions enough, you'll hear people say, "Oh, electric vehicles are going to have a massive impact on the system, and we're going to have them plugging in to transformers, and so forth, and it might blow them up, and we're going to have all these problems." Well, hey, that might be the case, so let's try it out, let's get ourselves a nice battery pack where we can simulate 1, 2, 3, 4, 5 electric vehicles, let's set up some 25 KVA, 50 KVA, 75 KVA transformers, and let's simulate loads on those transformers similar to what we see from, you know, a number of homes, and then add a couple of electric vehicles on there. Now, I'm kind of wandering, I used to talk to our General Manager and say, "Hey ,I want to blow up a couple of our transformers," and he would kind of look at me like, you know, "I don't think so. We know you're in R&D, you're not going to blow up our transformers," but we have a great facility called Hedge where we train our linemen and we can actually set these transformers up and put these simulations on there, and actually real time, real temperature, test these. And I want to see, you know, does it blow a fuse? Does it blow the transformer? Does it do nothing? You know, because we need to be prepared. The electric vehicles are coming next month, they're coming, and what's going to happen? These things are going to condense in certain areas, it's not going to be spread evenly across a utility, so you need to know, if you put one or two on a distribution transformer, what impact it is going to have, and we intend to find out. It will be a two-year project, and then I'm going to use the battery pack for what they call V to G, so Vehicle to Grid simulations where we're actually going to take a look at taking the battery pack and putting energy into the grid during peak periods, and so that's another project, so this battery pack will have like, you know, a four-year life before we start loaning it out to other people.

And then, battery PV optimization, the picture there shows what used to be a hydrogen fueling station, there is 80 KW of PV there, we took out all the hydrogen and we're going to install something like 20 level 2 electric vehicle chargers, which are like 240 volt, and one level 3 charger, which is a DC charger, in the 400 plus volt range, and we're going to install about 150 KW flow battery there to see how we can optimize grid operations with electric vehicle charging, integration of renewable resources, and the battery. So, these are all great projects, and I was told I was supposed to talk about open ADR, which I guess, you know, I see Auto-DR and open ADR, the document I read recently said that open ADR is the new name, and I'll let Mary Ann correct that or not, and that Auto-DR is the old name, so I thought, okay, I'll put "open ADR" on here. We got $1.5 million in ARRA specifically towards Auto-DR, Open ADR, and our approach is to implement it first with our partners in the ARRA grant, which is Los Rios Community College District, they have four campuses in our service territory, California State University, Sacramento, which has one campus in our service territory, and Department of General Services. So, once it is incorporated there, we'll see what the impacts are and how it works, and then our hope is to roll it out into a regular customer program after that.

So, summary, I think it is going to play a significant role in the future. We're doing a lot of interesting projects around it, and I'm going to be interested to see the results from those projects. I think storage will be a viable option for us, like I said before, right now it's more of a niche application, but I see that growing, except for the pumped hydro stations. So, thanks.

MR. GRAVELY: Thank you. Any questions? He's got his hands and everything?

MR. PARKS: Yeah, we're messed up! Okay.

MR. GRAVELY: Everybody is waiting for that class on proposals here. Okay, so we're going to shift now for the last three presentations and talk about Automated Demand Response and Open ADR. So, Mary Ann Peitte is our Director of Demand Response Research Center, it's been at Lawrence Berkeley National Lab for quite a while, I'll let her tell you how long and, in addition to what she normally does, I challenged her to come up with Auto-DR as a Grid resource, and we'll hear today how that's working.

MS. PEITTE: Thanks, Mike. So, I'm Mary Ann Peitte from Lawrence Berkeley National Lab, and let me first answer the question about Auto-DR and Open ADR, the word "Open ADR" doesn't actually show up in the Powerpoint anywhere, which is not normally how I do my Auto-DR talks, but I will explain its use, it's very simple. Open ADR is the specification for the communications, so the reason we started calling it Open ADR was to distinguish it from proprietary Auto-DR, there is a lot of proprietary systems that aren't open. Open means it's an open API, so the application programming interface is in the public domain, and you could build an Auto-DR system using the Open ADR specification. The reason we developed it was to allow low cost automation. So, an open API allows innovation for interoperability, and we're very active in the NIST Smart Grid Standards. We hope to actually be issuing Open ADR 2.0 in the spring, that will be an SDO approved – national FERC approved, open ADR spec, so I want to thank Mike Gravely for his many years of support for Auto-DR and Open ADR, there's a lot of folks in the audience today who have contributed to this presentation, Nance Manson and Dave Watson from LBNL, Betty Seta from KEMA, Dave Hawkins and Walt Johnson have been involved. And today I'm going to walk through some material that is related to the fast Demand Response and the Grid integration.

I'm going to go through seven sections in my talk, and this is a Scoping study, so it's not a formal report yet, but we hope to finish it up before Christmas, but I'm going to talk about why we're doing it, how Automated Demand Response relates to traditional ancillary services, a little about the experiences with Automated DR, and the activities in the State of California. The methodology that I'm going to review with you is related to actually coming up with the bottom up estimate of the Automated DR potential for these kinds of resources, so I'll go through a little about the exercises we've been through and how this links to the CAISO program, so what the ISO is looking for, and the preliminary resource estimate, and where we're going with this work.

You've heard today about the Renewable Portfolio Standards, we've gone through that many times today, and that the wind and the solar resources are intermittent, and there's a need for improving our ability to manage the Grid, four gigawatts of ancillary services, four gigawatts of battery storage was discussed in the KEMA report, Automated Demand Response has been shown to supply ancillary services, and I'll talk a little bit about that. So this concept again is coming up with a preliminary estimate on what is the size of the resource, and what kind of research is needed to support growing the availability of Automated Demand Response to facilitate more renewables on the Grid. The picture there is the automated critical peak pricing data from – I believe that is a 2008 or 2009 event, so essentially what we've been doing in California is automating Demand Response, all three of the electric utilities, the IOUs have an automation server, Open ADR is a client server technology, so the building is continuously listening to signals from the automation server. I'm not going into a lot of detail about Auto-DR infrastructure in this talk, but more talking about the resource capabilities.

The things that are discussed in this slide, the first two bullets are related to the fact that ancillary services are traditionally with fossil fuels at a high cost. We've talked about a variety of costs about batteries today, and essentially the idea is that the Demand Response can provide some of that response. How much is one of the questions, what's the price point is one of the questions, we've been able to install Automated Demand Response with the utilities in California at a couple hundred bucks a kilowatt, and that includes recruiting the sites and configuring the systems. One of the things about Demand Response is that we do not retrofit the controls, generally. Generally, we're putting in automation and using the controls that are existing in the buildings. So, in the scenarios that I present, I talk about the existing controls and what future controls may be able to support. Automated Demand Response can also lower the carbon footprint because we know that there is a synergism between energy efficiency and Demand Response, and it's very often we see that, when people try things for Demand Response, they actually migrate to energy efficiency. So, the infrastructure that we're deploying to deploy Demand Response can actually also facilitate energy efficiency. How much that is done is somewhat anecdotal, and it is something to keep an eye on as we move forward. But the more we integrate energy efficiency and Demand Response on different time scales, the lower the cost will be for California to achieve its goals.

This slide shows you a little bit about our past capability and what we've been doing. We have over about 100 megawatts in California of Auto-DR. And we call the programs Auto-DR Programs, so if you go to San Diego or Edison or PG&E, they're called Auto-DR Programs. Open ADR is what is used to facilitate the Auto-DR. The programs have tended to emphasize retail price response, so critical peak pricing, peak choice, demand bidding, some capacity bidding. We've done very fast Demand Response, so we took three sites in 2009 that were on automated critical peak pricing, and we transitioned them to the participating load pilot with PG&E. The participating load pilot was very fast response and we were able to get the sheds in less than a minute. The graphic on the bottom left is the fast Demand Response. We were able to take a site that had been using an infrastructure for day-ahead critical peak pricing and were able to get the sheds in less than a minute. We had four-second telemetry on those sites, and that gives us the confidence that many of these loads can respond very quickly.

On the right, you'll see cold winter mornings in Seattle, so we're moving from a time where we focused on hot summer afternoons to any time DR. And that is a big challenge for us to understand the loads in California and how what we've developed for mostly commercial and industrial, and I want to emphasize that the material I'm presenting today is commercial and industrial loads, but we're looking at how do you characterize the CNI end use load for fast Demand Response that's available any time.

Now, there are certainly a lot of challenges, and it's very important to be clear about those challenges for Demand Response. The economic incentives need to be more clear, the resource does vary based on temperature and time, and there's not a lot of experience with the midnight Demand Response, what Demand Response do we have in the middle of the night, that's not a key time, those morning ramp periods, which I'll talk about, those are very important, those ramp hours in the morning and the ramp hours around dinner time. The ancillary service requirements for Auto-DR may be higher, they will be higher than the day ahead critical peak pricing kind of things that we've done, the monitoring, the verifications, the telemetry, and we actually are using dedicated networks to push the Internet signal to the site, that is very fast technology. So right now, we've been installing Open ADR Auto-DR systems using the facility's existing Internet system, and I didn't say that earlier, but Open ADR can be sent over many communications, technologies, and we're currently using the Internet for most of the implementations, although we've done demonstrations with others, and we are actually looking at Open ADR over AMI, and things like that. So, the information and the price signal, the information and the signal is what Open ADR is. We send prices and we send reliability signals, so it's a language for these interactions to signal to the end use load to do something. The very last one, the portfolio management, most of the work that we've done so far has been focused on communicating with the facility. We haven't done too much aggregation and load shaping of the portfolio, but clearly that is an important part as we move from understanding how an individual building performs to an aggregated portfolio. But there's a lot of capability with this technology to automate end-use load control in specific geographic regions.

So, the methodology we used for this analysis was organized around understanding the electric loads for the commercial industrial sector. We used the commercial end use survey, the CEUS data, which is by building type and by end use, so we know the AD760, the hourly loads for the State of California for offices, hotels, restaurants, and retail, and then, on the industrial side, we looked at a variety of the industrial loads that we thought were the best opportunities for Demand Response. So we looked at the total load and then we looked at what percent of that load is controllable. In the commercial buildings, we have eight years of experience with commercial buildings, and about a third of the commercial floor space currently has an energy management control system. We've been automating the Demand Response using the energy management system, the Building Automation System. So, when we say percent controllable, we're referring to can you get to – is there centralized control? And with HVAC, there typically is in large facilities with lighting, some of them have them, some of them don't. And then, when we go to that HVAC load, what percent can be reduced? So, we come up with estimates of the total capability. We have been looking at the statewide load data, as I said, so we've done the bottom up analysis of which are the loads that we think are feasible for this kind of Demand Response, and we've developed multipliers that look at the renewables integration issues in two categories. We've done a two-hour category and a 20-minute category. The two-hour one is similar to what we've been doing and most of our price response have been four to six hour events, so we'll re-set a thermostat, a zone temperature twice. So, a two-hour duration is a typical short term duration in a sense. A 20-minute duration means that you're going to get it done quickly, within five minutes, sustain it for 20 minutes, and then let it go back to normal. So, we're very careful when we look at an end-use load, whether it can respond on that time scale, and I'll make a couple of comments about that. So, as I said, we've looked at building type, and we've looked at end uses, and then we looked at the industrial loads, and we have an industrial Ag water program in the PIER Program that has been part of our knowledge for that part of our research.

I've got my Mac to PC messed up a little bit here on the Auto-DR slides, but here you will see the graph in the upper left-hand corner shows the wind on the Grid, and the blue is the load shape, and you'll see we care about those morning ramp hours and the afternoon ramp hours. So, Automated Demand Response can help shift load to the night time, which I haven't talked about yet, but I'll get into some of the terminology in a moment, so we care about the daily peak load management and the ramp smoothing. The current CAISO programs are reg-up, reg-down, non-spin, and spin. We've been looking at Auto-DR for the top three, not the spin, but the reg-up, reg-down, and the non-spin. So that means these responses have a variety of different characteristics about how quickly we have to see the response, and how long the duration is.

Now, this graphic is a plot on the X axis it says advance notice of response, and on the Y axis, it's the duration of the response. The top right programs are the ones we've been doing for many years, capacity bidding, real time pricing, critical peak pricing, peak choice. Typically, a lot of what we initially did was day ahead. When you do day ahead, you can do things like pre-cooling, when you do day ahead, and we're doing large industrial loads, we have one site that is nearly 10 megawatts, some of those industrial sites need advance notice, so they cannot do a 10-minute ahead large shed, they need advance notice because it'll influence their work shifts and their production cycles and things like that. To the left there is the non-spinning reserves and those are very fast notification and shorter duration, and the reg-up, reg-down spinning reserves are even faster and shorter duration.

So, we're moving from summer time, day ahead, to any time fast. Shorter durations. So, we're trying to understand what that means for an end use load. We want to know how often you can call it, and what kind of disruption it might have on the process. The bottom slide is one you've seen several times today, already, but I've added something to it, I've added the Demand Response oval because Demand Response has some features that are similar to batteries. At the top, you'll see shed shift charge and discharge. A lot of what we've been doing is shedding, so we actually changed the service level. We changed the set point, we changed the lighting level. But sometimes we shift, and when we pre-cool, we shift. One of the things I used to talk about was at Del Monte, when they harvest the tomatoes, they have to get the tomatoes during the harvest time, nobody is going to stop them, but they make the ketchup year-round, and when they freeze the tomatoes and bottle the ketchup, that's a flexible load, they can do ketchup any time. So there are examples of loads that are flexible. So, the key is, is a load flexible? And we have not fully evaluated all the loads in California for their flexibility. Their flexibility is an issue, but how much advance notice do they need? So, as we explore how flexible end-use loads can be, we need to understand fundamentally what we're doing to the load. When we charge, we are actually using the mass of the building, or the frozen products, and that, we believe, is a very valuable aspect of Demand Response, where we're actually, of course, using a demand-side system to help on the supply-side issues. And that's the most important thing here that I haven't said, but I think you all understand, is that the demand side is getting some information about the supply-side issues, and participating in the grid. So that's a new paradigm here. Now, when we discharge, if we are resetting the temperature of a frozen food product and it's going back to – say we sub-freeze by seven degrees, and now we let it go back up to the original set point, we're actually discharging thermal storage by using the mass of the products.

This graphic is similar to what I said, but giving you a little bit more detail. On the left are end uses and the industrial loads. We have HVAC and lighting in commercial buildings, frozen and refrigerated warehouses, data centers, agricultural pumping, and wastewater. We've found actually some wastewater facilities have storage, some don't. So, depending on how flexible they are – their flexibility depends on the storage that they have built in. A lot of it is for stormwater runoff, so Municipal wastewater is an example of a load that may have a lot of storage capability. So, you'll see here modulating vs. on/off. Sometimes we're turning loads off and sometimes we're literally resetting set points and changing at the service level. We're also responding on different time scales. Some of the loads can respond in five minutes, some of the loads take 15 minutes, so this is a – all of these are things we've actually done before, so we have some reference to field studies and scoping studies that provide us with evidence that these are real loads that we can build on.

Now, this slide shows you four graphics, the left-hand here is the HVAC and lighting, and then the industrial loads, so we see at the top the highest hour and the lowest hour with today's controls. And then, if we actually improve the controls in our facilities, we are reaching almost two gigawatts of potential for this kind of technology. Today, we are at not quite a gigawatt, and the gigawatt is summertime, and the .25 gigawatts are 250 megawatts, that is a wintertime, nighttime capability, so we've been spending a lot of time looking at when do these loads exist and how flexible are they, and what is our back of the envelope, bottom up estimate of the capability.

This slide here shows – the blue is the two-hour duration and the red is the 20-minute duration. Some loads can be called very quickly, and we can see the reduction in five minutes and sustain it for 20. Other loads are two-hour loads, and this is the same four graphics I showed you before, but these are the capability by time of day, so the 8.8 gigawatts is what is available in the summer on a hot day, and on the winter, with today's control systems, in the middle of the night, we're at about 250 megawatts. And then, when we improve the controls, which allows us to get to the end-use loads, the loads almost double – more than double on a couple in the 1.8 gigawatt case.

This is my last slide, and so we're concluding that the initial estimate is something like between 250 megawatts to .8 gigawatts of today's control capabilities. Those are loads that we think are readily available, at a reasonable price point. Those are loads that we've seen demonstrated over the past eight years. We've not done healthcare, for example, or hospitals. We've not looked at hotels. Some of those control systems are more distributed today and not as centralized, but as we retrofit the controls, we're going to be able to touch more of those end use loads, so we're increasing that. There is research to be done on the economic evaluation, which are the most cost-effective to go after, what additional off-peak data are needed to do these studies to better understand and firm up these numbers, and the geographical considerations. We want to do some of these activities near to the problem areas on the Grid. So, that gives you an idea of what we think the capability for automating Demand Response is for these very fast DR resources in California. Thanks.

MR. GRAVELY: Questions? No questions at all? Okay. So, we will have a public session here in about 45 minutes to answer questions.

MR. JAMALI: This is Joseph Jamali, a consultant. You referred to improvement in controls. What are you referring to, specifically?

MS. PEITTE: One of the best examples is our increase in the Ag pumping resource. There is a company that is doing a wireless agricultural pumping platform to get to Ag pumping as a load. If you install dimming, lighting, for example, that supports both energy efficiency and Demand Response, your ability touch more lighting increases, so those are two examples. So, all of these increases are related to improving the end-use load control and having better access to controls.

MR. JAMALI: How about HVAC?

MS. PEITTE: HVAC, definitely. As I mentioned, about a third of the commercial floor space has an energy management system. When you just have rooftop units, you may not have the rooftop units talking to each other, so you have to automate each of them individually, which is more expensive than going to a single centralized system.

MR. JAMALI: Okay, thank you.

MR. GRAVELY: And Mary Ann didn't mention, but specifically, also one of the values of the ARRA projects and the National NIST efforts is that many of the control companies are starting to consider or are already doing – embedding open Auto-DR protocols into their systems, so the ability to reach more loads and the ability to reach them at a much lower cost is something that we will probably see as a result of the large insertion of Smart Grid money by ARRA.

So, I would now like to turn over the opportunity we have now to Albert Chui here from PG&E, he is going to share with us PG&E's perspective on Auto-DR, intermittent renewables, and then, after him, we'll also hear from SCE.

MR. CHUI: Hello everybody, I am Albert Chui with Pacific Gas & Electric Company. Thank you, California Energy Commission, for this opportunity to allow us to share our points of view and our vision on how Auto-DR can potentially use for addressing intermittent and renewable issue. So, first, actually, I need to apologize, I was under the wrong impression that the presentation is only 10 minutes, so I have only prepared for three to four slides, you know, but I can definitely talk 20 minutes, maybe even more, but if not, you know, I will allow others to have more time.

PG&E has started to engage Auto-DR starting in 2006, and in 2007, the CPUC ordered a three-hour use to start engaging Auto-DR activity, and for the last few years, we have offered Auto-DR program to our different customers. And, oh, actually, before I address these questions, I would like to provide an update on our Auto-DR programs. So, at this moment, we have enabled about 45 megawatts of Auto-DR load, and hopefully by the end of 2011, we will have 75 megawatts of automated. Both PG&E and Edison are big supporters of the Open ADR standard and, you know, as Mike suggests, it's definitely a necessary thing to do because we want to make sure that there is more control company and more vendors providing the Auto DR service, and technology, so that, in a utility perspective, we can implement Auto-DR programs in a more cost-effective manner. So, both PG&E and Edison are big supports on that. And also, we are working with Honeywell, which won an ARRA funding projects to promote Open ADR technologies within California, and they started at Edison's service territory first, and now they migrating, you know, into the PG&E service territory, so we will definitely plan to work with Honeywell to promote Auto-DR technology to our customers.

So, in general, PG&E has two Auto-DR goals, well, obviously, first we want to accomplish the different objectives that, you know, we have outlined to the CPUC, you know, on Auto-DR program, which includes engaging more customers into the Auto-DR technology. But also we want to use the Auto-DR technology to integrate with emerging technology products and, throughout the days, you know, I have realized that a lot of energy storage and permanent load shifting technologies is also considered emerging technologies, you know, on the utility demand side management perspective. So, I think there is this tight integration opportunity, you know, to use Auto-DR for permanent load shifting or energy storage type of emerging technology. And then, also, the second objective of Auto-DR is how we can use the Auto-DR technology and this communication channel, and this open protocol to provide DR resources into a product of the California ISO market. As all of you are aware, PG&E has been, you know, as a matter of fact, California IOUs have been engaging with Demand Response and note management type of activities, you know, for a long time. But throughout the years, there is definitely a gap between the DR resources and California ISO activities. And we feel like Auto-DR would help us to engage Demand Response resources into the ISO market, getting DR resources into the ISO products, as one of the ISO's products such as energy, capacity market, ancillary services market. And now I'm going to talk about exactly how we are going to – the different research that we have done to help us prepare ourselves to look at exactly how we're going to do that.

So, as I mentioned, we want to start looking at the technical feasibility of providing the different services to the California ISO to mitigate the following, which is increasing ramping requirements, over-generations, and intra-hour variability. We have done – well, we are in the process of doing one pilot, and we have actually completed the participating load pilot, which was designed to address the feasibility of providing services to CAISO. Okay, so, the participating load pilot that we had in 2009, the main objective was to demonstrate integration with CAISO automated dispatch system with Auto-DR demand response automation server, and the creation of a feedback mechanic system to allow customer response to provide closer to the instructive supply by the CAISO. And in my opinion, actually, that's also one side's benefits, that me and John Hernandez, the Program Manager of that project, have realized, you know, with this pilot is, you know, obviously Demand Response touches on many different areas at PG&E, that includes Demand Response, of course, energy efficiency, Demand-side management, marketing, customers, but then there are actually two major departments that we work very close with, that is sometimes kind of behind the scenes, which is Energy Procurement and Transmission and Distribution. And we work with Energy Procurement when we could tell DR events, okay? Obviously, we need to justify whey we call a DR event, and wish the DR event to call which resources are available, and we work with Energy Procurement to determine a lot of those things. And all along, I would say that, you know, it is just because of the activities and the fact that demand resources have not been – that is not a major tie with the CAISO market. Our Energy Procurement looks at Demand Resources as reliability resources, they look at this as – they don't see the tie, you know, they don't see the link between DR and the ISO market, even internally, you know, we have those kind of silos and challenge to overcome.

And one of the major – John is doing a very good job in implementing this pilot. At the end of the pilot, Energy Procurement has a different perspective on Demand Resources, okay, we have Energy Procurement staff, you know, internally at PG&E, that starts looking at DR, you know, a different perspective. And I'm sure that there are people that already agree that DR is a good resource, you know, in energy procurement, but definitely this pilot helped those people to ensure that DR, Demand Response resources, can be used for different products in the ISO market, but not -- just kind of go beyond the reliability perspective.

So, this is an architectural diagram that we have with the participating load pilot. Basically, there is a Demand Response Automated Server that PG&E talks to, and then we are using different technology to get four-second telemetry on the customer side, and the customer drops load on both lighting and HVAC, and we have three customers that have this type of telemetry installed. And, again, the objective is to find out if we can use lighting and HVAC load to participate and bring the DR resources into the market because if, let's say, for some reason we have identified a lot of barrier, right, then we know that, we are maybe a little far from using Demand Response, or Auto-DR, to address intermittent renewable resources, but with the pilot, we have successfully demonstrated that Demand

Response resources can be used to drop load, you know, filling all the requirements, except we did ask for one exception, which is I believe the one megawatt exception, it needs to be one megawatt minimum load when we bid into the ISO market, but the fee customer is in a different category, low elevation point, and so we did ask ISO for this exception. But other than that, we have successfully demonstrated that Demand Resources can be used for this.

And now I'm going to talk about – this is just one of the graphs that Mary Ann showed exactly what happened on that date, and the blue line is the forecast data, the red one is the hourly forecast with reductions, and the green one is the actual five-minute data. Okay, so with the participating load pilot as a stepping stone, now we want to tackle a more advanced agenda here, is how do we use Demand Resources to address intermittent renewable resources, at least the potential of it? Because, just the system alone, it is a participating load, the IR, Intermittent Renewable resources demonstration, required different system that was used for the participating load pilot. So, not only do we need to look into how to integrate a different system with Demand Response, for example, ISO used ADS, Automated Dispatch System, on the participating load pilot, now we are trying to connect to the AGC, which is the Automatic Generation Control with the ISO. So, there are different challenges to overcome and different technical experience that we need to gain from implementing the different systems. So, again, we want to find out whether the coupling of DR or thermal energy storage can provide regulations for ISO market. We want to integrate the AGC, we have addressed, we want to analyze the optimizations of thermal energy storage and a possibility to provide service and may be able to address the intermittence issue. I do want to point out that, actually, is it on the next slide, okay, well, not yet. Okay, so I do want to point out that, on the Intermittent Renewable resource, what is unique about this specific pilot is that we will be identifying customers that can provide energy storage with – you know, not with the traditional energy storage and the technologies that people demonstrate in the morning sections of today – we want to look at how customer operations such as refrigerator warehouses, and maybe using pre-cooling, okay, as energy storage, with this pilot. When you think about that, that's a totally different concept, right, with batteries, with pumped hydro, and all that, because people have that now, right? This may be the control that is required, but refrigerator warehouses have frozen food now, okay? Buildings have thermal mass now, okay? So, how we can use the existing resources, okay, as energy storage, to look at how we can tap into those resources and adjusting customer energy usage and operations differently, so that we pre-cool earlier, or we pre-cool at a different time, or maybe we freeze the food to different degrees, or to lower or higher degree, based on the time, so that we have a better understanding of how those resources can be used for energy storage. And, interestingly, we are still in the process of identifying customers and working on the pilot, but interestingly, the first things that we kind of realized is that the requirement of a sophisticated operation system on the customer side, okay, what that means is that, if the customer energy management system, or if there is some kind of energy software that can help us to predict, or forecast, or analyze a specific building thermal mass for peak cooling, that is a good type of software. If the customer's operations software can keep track of the potential of the frozen goods, okay, on a specific time, so that we know exactly if the refrigerator warehouse is full, half-full, or in the 50 percent capacity, or in the 25 percent capacity, then we know because we already know the load shift energies, right? So we know exactly how much load is available, okay? So, it turns out that forecasting on customer load for Auto-DR projects, for using Auto-DR, for the Intermittent Renewables, it is all tied together. So, I think we have Auto-DR, which is a good thing a good communication channel, and we are working on the Open side, but I think it was an eye-opening opportunity for the utility to look at what other pieces are missing in this whole picture, so that we can start using existing resources, or existing infrastructure, so that, at the end of the day, it is very cost-effective – well, it is more cost-effective to use DR for Regulations, energy or other – for ancillary service type of measures.

So, to conclude, the activities that we have with Auto-DR, we definitely want to use this technology, the program and, again, how we can integrate all the technology together to beat DR resources into the ISO market using positive Demand resource channel, or other types of – an identified channel in the future, and definitely it allows the opportunity to look into different things. After this specific IRR, we will also propose to CPUC an additional IRR project that looks at like a second phase of how we can use Demand Resources to further address intermittent renewable resources, and we are working with – we will propose a permanent load shifting program, depending on the recommendation of the POS study with the Demand Response Measurement and Evaluation Committee, and again, all these activities is to develop low-cost DR resources that can potentially provide products for the client. So, any questions?

MR. GAVELY: Questions?

MR. CHUI: Yes.

MR. JOHNSON: Hi, this is Walt Johnson with KEMA these days. I had a question following on both what Mary Ann was saying about moving Auto-DR to more rapid timeframes, and the second project that you're talking about on integrating AGC with Auto-DR. The push of the signal to the Demand Response Automated Server can happen instantly, and the four-second interval that AGC dispatch is on wouldn't be a problem, but given that the resources poll the DRAS - and originally I think we're polling it like 10-minute intervals -- you could clearly shorten that, it is configurable; but is there a limitation, or do you see any issues with having to poll on a one-second, or maybe sub-second sort of interval? So, is the protocol changing or emphasizing sort of a push alternative to the polling mechanism that has been, I guess, traditional, or the established mechanism in ADR?

MR. CHUI: I will let Mary Ann discuss the details.

MS. PEITTE: With the critical peak pricing day ahead, it is about every minute polling, as you say; but with this project, it's a one-second push, so it's dedicated Internet, so it is an AT&T Network, right, Ed? Yeah. So it's very fast, one second to the controls.

MR. GRAVELY: More questions?

MR. CHUI: All right, thank you.

MR. GRAVELY: Thank you very much. So now we'll get a chance to hear Southern California Edison's perspective, and Jeremy will introduce that, and then we'll have a question and answer session, but if it's this quiet, that's going to go quick. Go ahead. May be not.

MR. LAUNDERGAN: Perfect timing, everyone is just getting to be really relaxed after lunch. I'll try not to pay attention to any snoring. I have to apologize to the audience, I did not realize it was gray suit day. So hopefully you'll forgive me in that. I also have to apologize, I only have five slides, including the coversheet, so we can probably move along relatively quickly here.

As we heard with one of the first presentations this morning, CAISO really will be the coordination for covering for Intermittent Renewables. You may have – or they had forecast for sunny days, for a certain amount of wind, and you have more clouds or the wind doesn't blow. I'm actually a sailor, so I know the whole thing about the wind not blowing when you want it to. So, through the various markets that CAISO has, they can then trigger other resources to fill in for the ones that don't show up according to schedule. Specifically, in the short time frame that we're talking about here, you have ancillary services. Now, for Demand Response, over the last couple of years we've worked closely with the other IOUs, CAISO, and other stakeholders to bring two product offerings to bear, really, starting this year. I guess the market for Proxy Demand Resource became available in August after FERC approved the tariff modifications in July, and we're getting to the last bit of a similar approval process for the reliability Demand Response product, so those are two ways that the Demand Response resources are going to be able to play directly in the wholesale market. So, specifically, a Scheduling Coordinator that represents a PDR Demand Response resource can bid into the day-ahead energy market, okay, that doesn't do us much good for intermittent renewables, day-ahead in real time non-spinning reserve market – ah, now we're talking, five-minute real time energy, yeah, that's in there, too. And eventually the HASP, which can also kind of suit if it looks like the renewables won't be delivering for their entire scheduled sequence. So, one of the things that we discovered almost by mistake when we did our pilots two years ago was about the contingent flag. I misunderstood what that meant originally, and John Goodin who is here in the audience set me straight, but a contingent resource that you bid in is a resource that is sitting there and will show up if something else really doesn't perform as it is scheduled. So, with a contingent resource, a contingent ancillary service resource, would show up if another resource doesn't perform as scheduled. So, in the case of an intermittent renewable, what you might do is take a limited resource Demand Response product, something that could only be dispatched, say, 12 times a year, or 700 minutes a year, whatever you might have for constraint, and register that as a contingent resource, then it would become an available resource in the wholesale market if something else, either an intermittent renewable, or even conventional generation, doesn't perform as anticipated. This mechanism could be used for any type of resource not performing. However, as we've also been working with the other IOUs, as well as CAISO, there are some pretty big challenges to Demand Response actually playing in ancillary services. The big one is the telemetry. So, in order to play in the ancillary services market, you need to near real time monitor the availability of that resource and what it can deliver, and what that translates to is a four-second refresh from whatever aggregation point is with the one-minute refresh from each and every end point. So, we've been spending a lot of time looking at different alternatives for doing that. Albert was talking about some of it and we're looking at some Internet back polls, instead of having the dedicated telemetry solutions, which, by the way, can run $30,000 a year, and for every air-conditioner out there for our programs, that's probably not very affordable. So, we also have the five-minute settlement requirement for basically the near real time type of markets, including, I think, HASP has a five-minute settlement, and we're deploying our Edison SmartConnect, as well as our current RTM meters for large commercial customers, those have 15-minute intervals for commercial and industrial customers, and one-hour interval for residential. So, one of the proposals is, well, just take that 15-minute interval, divide by three, and then you've got three equal segments of five-minute intervals. Sounds good until you do the math and that kind of under-estimates your performance by 15 percent, on average. So, those are some of the things we're working really closely with CAISO to figure out, and also for residential customers, because one of our largest resources, actually air-conditioning cycling, where we've done a lot of testing, and currently we have 350,000 customers with 450,000 devices, providing 750 megawatts in a program operational today. So, that's where I've been spending a lot of time over the last two years, seeing how that resource can make itself available in the ancillary services market, to address, in part, intermittent renewables. So, with a one-hour interval, what can we do with that? Well, we also have existing SCATA systems that, oh, by the way, already provide that four-second refresh, and also provide aggregated metering points for everything, say, underneath the distribution substation, we're completing that research right now, and that report will be filed with PUC at the end of January.

And there is also the challenge of actually figuring out how to reconcile the retail market, the customer compensation relative to the CAISO wholesale market. The issue here is that CAISO doesn't run a capacity market, a lot of the DR value currently is through capacity that is determined through resource adequacy. As a result, resource adequacy payments for Demand Response are outside of the wholesale market, and therefore it becomes challenging to actually come up with the retail compensation that includes the capacity value from resource adequacy, as well as whatever energy payments come from the CAISO wholesale markets. Some of those issues will hopefully be tackled in the CPUC DR Order Instituting Ratemaking Phase IV, Part Two, which just came out, I think, last week, and I was spending all day Tuesday replying to some of their very good questions associated with that. I encourage people to participate if they're interested in some of that question.

So, earlier we heard from Mary Ann and Albert on Auto-DR, I'm actually going to take it a little bit more generic. Automated Demand Response just being something that is triggered automatically, regardless of protocol or anything like that, or customer segment. And what we need is something to be able to react quickly, it's got to be automated, and the old way of saying, "Hey, you're on critical big pricing and it's critical peak day, and you call the person, or page the person, and they run around turning off lights in their factory, that just won't work for this. So, it's got to be automated, and it's got to be relatively quick. We use Open ADR that Mary Ann was talking about, which uses the Internet for the communication for our larger commercial and industrial customers. We are also deploying a advance metering infrastructure system that we've branded Edison SmartConnect, which will be using Zigbee Smart Energy profile, and we're anxiously awaiting Version 2.0 to address some security concerns and others, as well as just robustness of the protocol. So, that will be addressing our residential small and medium commercial and industrial customers. We actually expect that some customers that start getting introduced to Auto-DR through a Smart Energy profile will want to, say, graduate to a little bit more robust stack in the Open ADR, so that is something that we're going to be working with our customers on, but either way, those are two automated ways of dispatching to customers to react to wholesale market signals, there may be some latency on the AMI network, we won't know until that is fully deployed. So, we know that our current AC Cycling Program can respond well within the five-minute, we've done multiple tests over the last, what, probably four or five years, including the spin or reserve pilots that we've done. But, as each of these technologies get deployed, we need to determine the latency to make sure it can actually meet the five and ten-minute dispatch instructions.

And we're embracing the Open Standards, as Mary Ann also mentioned, Open ADR and Smart Energy Profile 2.0, both of which are identified by NIST, so there are a lot of folks out there going, you know, "Go now! We've got a solution, plug and play, off we go!" But, we really need this stuff to be open Standards because we cannot have a vendor lock and any sort of large scale deployment of something would only have a sole source deployment, that's not really sustainable in the future.

So, from a process standpoint, this would be the process for Demand Response actually reacting to ancillary service signals from CAISO, and this is the exact process, a little bit higher level than the actual process, that we did for the pilot two years ago. We had real time telemetry monitoring, we actually used the sample monitoring for that, sent that signal both to our back office, as well as CAISO. We bid the load into the day-ahead market, we received dispatch instructions from CAISO, those instructions were dispatched to the AC cycling, we measured the load drop, and then we settled. Now, for the pilot two years ago, we were using the AC from a military base, and we had 3,200 air-conditioners out there, on a good hot day, that's five megawatts, it went like this [snaps]. So, this is about five megawatts at the drop of a hat. What we did here was what we call 100 percent cycling with no randomization, it was literally like hitting a light switch, turned them all off, turned them all back on, all at once, I did that type of a deployment because I wasn't exactly sure that we'd be able to see it, boy, was I wrong. So, that little hump that you see after the Demand Response to restoration, that's what we call a "rebound," the reason that you do the randomization is so that you minimize that rebound, and you can do randomization over a five to 10-minute timeframe so that it's more of a ramp, rather than suddenly an instant restore, and suddenly every single air-conditioner is trying to catch up with itself.

This year, we did more general population testing at 12 different substations, so we used the test provision of our summer discount plan AC cycling, did two tests per substation for 24 events, total, combined that with all the findings from our production events. We had two system-wide events plus around four districts, how many nine events, that's out in the Palm Desert area where the system is a little bit constrained, and high load in the summer. So, we have a lot of data that we're crunching and, like I said, that report will be made available in January, along with our DR filing for funding for the next cycle. So, a lot of data, we're going as fast as we can, and look forward to continuing working with CAISO, the other IOUs, and hopefully CEC in figuring out how all this works.

MR. GRAVELY: Questions for SCE? No questions? So, I also would like to point out, this question has come up several times on Auto-DRs and Ancillary Service, and that is telemetry, I've thought a lot about it and discussed a lot about it, there are some values to already being on the loading order, and DR is at the top of the loading order right next to energy efficiency, so sometimes you can get a get out of jail free card for that – I'm trying to figure out what that means. But I do believe there is some opportunity in Auto-DR if we can demonstrate the capability and not assume the cost of direct two-way communications, but an alternative, very reliable estimating ability that could be revenue quality, and I think there are some options out there. Certainly, there are vendors who want to sell it to me. I think that there was some opportunity to do this in Auto-DR without having to have the two-way communications like we have currently in most systems, and that's one of the challenges that Mary Ann is also looking into, is how do we handle the telemetry, how do we handle the settlement, and how do we handle the verification.

So, we've had a busy day. I'd like to throw it out for questions here first, comments, most of the speakers are still here, I'll try the online next, and then I've got a couple closing questions, actually, to make the most out of today's workshop, and to help us prepare for the next IEPR workshop and other efforts.

So, does anybody here have questions or comments for any speaker, or for us, in general? Nobody in the room has questions, no comments? Okay, go ahead and open up the line because they've been very patient – oh, go ahead. I'll take the questions here first, and then we'll go online.

MR. MILLER: Rick Miller with HDR. A lot of the discussions today showed slides of the future with solar and wind, and the load is not concurrent with demand, but it is relatively smooth curve. That's not what Bonneville is seeing, they're seeing 2-3,000 megawatt ramps per hour, routinely – every week. That's at 3,000 megawatts of wind, they're projected to see 6,000 in three more years, a lot of that balancing will have to be provided by California because that wind is being shipped to California, in addition to your native supply that is ramping, how is that being factored into your long range plans? I don't see those ramps and that system – this system variability being factored in into the load curves that are being projected?

MR. GRAVELY: Well, two things, one is I would agree with you in general because I've been trying to find ways to document that with research, identify that. The first time we were very successful with the KEMA Report, we're doing follow-on work to that. We do have load modelers here within the Commission that do modeling, in addition to load modeling experts that we can contract with, so I would leave it in general for today as one of the questions, and that is what is a realistic estimate of the ramping requirements and the load requirements of 2020 when we reach our 33 percent. We, obviously, have a comment in NIST, but the ISO is responsible for doing their studies and working there, we do things to help them do that, the utilities are responsible for meeting their piece of that, so I think what has happened in the last year, at least in my mind, is a realization that the problem is bigger than we thought maybe two years ago, and we're starting to see that information. I think, as we get smarter and learn more, that number could go up. But what we're trying to do is provide options to address that also at the same time, from that area. So, I don't disagree that the challenge could be bigger than we portrayed today, I think the challenge as portrayed today is a pretty monumental challenge to put systems operating in time given, you saw some timelines for projects that are already 2017 or later, so I think that's something we have to work – certainly an area that we're interested in trying to quantify, trying to present to our Commission, trying to present to the Public Utilities Commission, to have to make these long term planning decisions, certainly. We see in our IEPR, there are estimates – you've seen presentations of different types of scenarios of high integration, low integration, different things, so we do those. For those of you who are online and here, if you have information you can share with us to help us understand, if you have examples, you know, the Texas example is used a lot of what happened there in their wind – the value of forecasting, whether it be for renewables, or for DR, was brought up today, and that's another element we'll take home with us to work on. So, I would tell you that I think we understand the problem, I don't think anybody here is prepared to quantify it specifically, but I do think it could be worse than estimated, but we need to find ways to do some analytical studies and come up with numbers that multiple parties can agree with, and then also respond to.

Ultimately, our goal here and the research that we do is to provide answers to the policymakers in our case, and the PUC, and the ISO, and ARB, and other places that worry about these issues, have the information so they can set policies for the future that are consistent with what we've done, and address the issues that we have from there. So, I would welcome any information you have of the kind of ramping rates we're seeing in Bonneville, so we can use that in our studies, and any other models or things you might recommend for us to look at or do some analysis with, certainly not in the next couple months, but over the next few years, we can do that. Go ahead.

MR. ALVAREZ: Tony Alvarez with PG&E. Udi Helman left already, but just to make people aware, that there is a 33 percent integration study going on, which is sponsored by the ISO. There is a working group also working with the ISO, we are part of the working group, Southern California Edison is, and a number of other parties, and if you follow the links that Udi provided today, you can find estimates of the amounts of incremental regulation, load-following, ramping that is required for different scenarios of the 33 percent. So, I'm hoping that the California Energy Commission can take advantage of that and, you know, leverage the work that has been done there, just put a plug also for PG&E, we have a model, simple spreadsheet model we put together to do similar calculations of incremental amounts of Regulation load-following, and unit commitment that is required for different levels of wind and solar generation in California. So, if you follow the links that Udi provided, you can find those estimates there. So, we will be updating the analysis using the new Renewable Portfolio Standard scenarios that the California PUC is planning for the long term plan -- for this 2010 long term plan cycle.

MR. GRAVELY: Okay, thank you. Other questions. Okay, so I'll go ahead, we have a question here for Frank, if you want to come up. It says, "Question for Distributed Storage Presenters," Frank is one of them, "…How do you define community energy storage in terms of size and distribution vs. transmission size of the breakers?" So, I guess, what do you define as distributed storage, and, if you would, since you kind of represented the Integrative and Distributed Industry, I guess the question is, in your mind, as a distributed resource provider, how do you define distributed resources vs. transmission resources, given the fact that, at the end of the day, you're providing 53 megawatts of transmission resource?

MR. RAMIREZ: A distributed – wow – for us, the grid scale nature of our distributed resource is realized through the aggregating enablement of our Smart Grid platform. For us, our – the amount of storage that we're able to deploy is a function of the number of air-conditioning units to which our storage module can be appended to. Each one of those storage units has an embedded controller that communicates with the other units on a building, but more importantly, tie back up through our NOC to the utility in a secure PI-to-PI communication. That aggregation enables the utility to look at that distributed resource in the same way that they would look at any generating resource on their system, whether it be a 25, 50, 75, or 100 megawatt gas-fired peaker, which is the resource that we make either unnecessary to run, or unnecessary to build.

MR. GRAVELY: Okay, thank you. Go ahead. So we'll take the questions in the room here, then I will try opening up the mics for people to call in or a couple questions here, and if you didn't hear your answer because of the mics, we'll try to fix that, too. Charlie, do you have a question?

MR. VARTANIAN: To add to Frank's answer, on the size and connection, I'd like to point to the American Electric Power Open Source Spec for Community Storage that discusses one utility's vision of a primary distribution connected device, 25 kilowatts, 25-50 kilowatt hours. EPRI is helping to broaden the involvement and get other utilities contributing to that Open Source spec, but that gives a good description about at least one form of community energy storage that is pretty well defined by ADP. I think a distinction there is connected to the primary distribution asset, not to the network grid, so categorization from a FERC, TDG, split standpoint.

MR. GRAVELY: And would you just repeat the size?

MR. VARTANIAN: A 25-50 kilowatt hour, or actually the capacities that are first being deployed in the early demos, but the spec actually widens that range a little bit, but the first actual physical deployed systems I know of are 25 kilowatt hour to 50 kilowatt hour – 25 kilowatt hour rating, or another way, 25 kilowatt hour rating for one to two hours.

MR. GRAVELY: EPRI agrees, concurs. Comments or questions from the room? Okay, we'll try this first, and if it works, we'll let people speak up, if not, we'll have you raise your hands on the WebEx and we'll call you. But go ahead and un-mute everyone. And we have a question from Carl Lenox, you can try first, Carl, if you're on the line, would you go ahead and ask your question?

MR. LENOX: Sure. Can everyone hear me?

MR. GRAVELY: No, we're getting an echo, but go ahead.

MR. LENOX: Okay, I'll try to do that. Starting with the comment, if you look at the Red Electra's System, the Red Electric, it's strikingly – their current mix and capabilities in terms of storage, hydro, and then I'm seeing pumped storage, their generation mix, the size of their system, it's strikingly similar to where California wants to be in the high renewables case in 2020. And it's sort of a very different operating reality than, I think, some of the modeling shown in terms of sort of these nascent emerging problems, they're actually doing it, they're actually managing it. They have almost 19.4 gigawatts of wind, they have 3.4 gigawatts of PV on their system, and they're operating it. So, I was wondering if we could get maybe some perspective on if there are any really significant differences there, is there something going on there that is not possible to do in California? Or, is it just simply that we haven't reconciled the modeling with the actual operation of this particular system and other systems with larger penetrations of renewables than we have here in California?

MR. GRAVELY: I'll turn to one of the other speakers. I'm afraid I don't feel qualified to answer that one. Any of the speakers here want to answer that?

MR. MILLER: I can answer part of that. Rick Miller at HDR. Spain has a very distributed wind and solar portfolio compared to the U.S. markets, so they're able to get benefits of diversity in location. They also have a very unconstrained, flexible generation system, they have about 4,000 megawatts of hydropower that has no constraints on it, unlike the Columbia River system or most hydropower systems in the U.S. And the other is, they're building about 1,500 megawatts of pumped storage, so that's aggregating it altogether is what Spain is doing to address their problem.

MR. LENOX: To be fair, though, I've actually had discussions with Red Electra, they consider all of their hydrogen to be constrained and, in fact, can't depend on it for flexibility in the late summer, I was told that by the System Operator. And to be fair, I mean, I'm talking about the system that is operating today, obviously to get a higher level of penetration to meet our 2020 goals, we're going to have to do more, right? But where they are today is our high case in 2020.

MR. MILLER: You make a good point. They do – its challenge about do they have enough fuel, do they have enough water for enough generation throughout the year, but their actual operations and their operational flexibility is unconstrained. But they're actively building grid-scale storage, they're implementing a number of things that are being studied here in the States, they're actually implementing it as part of an overall integrated resource plan.

MR. GRAVELY: Thank you very much.

MR. LENOX: Yeah, no question about it, right? But they're also currently operating the system without those at their current levels of penetration, which are levels of penetration that we're only talking about right now, so, anyway, I just wanted to get that comment out there, and if there's anything that we can do to sort of bring that operational reality to bear, particularly in these modeling exercises, I think that would be useful.

MR. GRAVELY: So any reports, presentations, or documents you would like to send to the docket so we have that information available to review would be useful. I'll end up with it, but the Docket address is in the announcement that you got the WebEx information from. Next speaker here from the ISO.

MR. GOODIN: This is John Goodin with the California ISO. I met with Red Electra a couple weeks ago, two or three weeks ago, and there is a distinction that makes the difference between how they count renewables vs. how California will be able to count, and that is that they actually get to include their large hydro, whereas California does not, and that is a significant difference – a 33 percent without our hydro system is a huge difference between Spain; in fact, if you were to include our hydro system with our current wind and solar, we're actually operating at a very similar paradigm to Spain today. So, that is a big difference. They do have a lot of diversity that we don't seem to have as far as their wind resources in Spain, as well. We have very concentrated areas with wind; theirs seems to be spread out throughout the country. So, anyhow, but I think the hydro is a significant difference.

MR. GRAVELY: Thank you.

MR. LENOX: It is, just to clarify my comments, in terms of the levels of penetration, I was speaking mainly about the wind and solar, and recognizing that sort of the total amount of hydro in the system there is similar to ours, even how we count relative to an RPS or not may be different, but in terms of total quantity, it’s more, I believe.

MR. GRAVELY: Okay, thank you. Other questions online, just identify yourself and ask your question.

Okay, so what I would like to do is a quick summary, and then I have a couple of questions for going forward. In general, I would like to thank everyone for participating and for speaking today. I would agree with Robert, this is a very great group to listen to. For the purposes of establishing the technology, I think we have established that storage technology, some are available right now as we speak, some are available soon, and some are being developed, so we have options. One of the things I’ll also offer, Merwin Brown is in the room here, I mentioned earlier, he was here, I think, when we mentioned, he works for CIEE and he is the Regional Manager for the office here, but we will be doing that vision for storage, Avtar will be the project manager, but CIEE will be the executor with some of the universities and their help. I suspect that we will probably need to have a workshop, public meeting in the

January, or early February timeframe, so those of you that are interested in participating in that development, of that effort, again, it will be a four to six months effort, so it's not going to be really long, but we are trying to capture information and trying to make that vision as useful as possible, so I would encourage you to contact either Merwin Brown at CIEE, or Avtar Bining here at my office if you're interested in helping us with that effort. We are very much interested in producing something that is useful for the industry and the regulators at the same time.

The other comment I'd have is a question and I'm going to throw it out, I've heard this probably for the last year at different meetings, and that is the comment that energy storage should be added to the loading order, and so, given the fact that the loading order is an energy procurement device, where we're procuring first energy efficiency, then renewable energy, and then advanced generation, and clean generation, and then fuel generation, or coal, whatever it may be, non-clean generation, I guess, is the term, is there anybody here who could help me understand, if we were to consider adding energy storage to the loading order, how would you define it to fit the loading order definition today? And trust me, I've been in Storage for 20 years, it's not like I have an answer, I'm asking a sincere question, if that is something we would want to advocate. And it has come up many times, it came up in the development of the AB 2514 and other times, and so, if we were trying to do that, and trying to find a way to convince the agencies in the state that manage the Energy Action Plan, to add energy storage, how would you define it such that it is consistent with the other definitions that are in that loading order? Robert?

MR. SCHAINKER: Yeah, Robert Schainker, EPRI. That's an excellent question. I've given it only a little thought, and I'm sure I won't be finished thinking about it, but it would seem that the loading order methodology for storage should include not only the sort of myopic arbitrage kind of ordering that you can do today, because it's just a cost-based thing, but include some of these – maybe all of the societal benefits, and particularly if we have CO_2 rules in the State of California, which we've talked about and I think will be occurring, there are societal benefits, and reliability benefits to add a shock absorber to the system, either to be small or large. So, I would say that we need to include some of these, or maybe all of them, at least in our thought process, these societal or California benefit in the ordering process. So, that requires a new methodology. I wouldn't – one of the things Tom Edison said years ago was, "The greatest thing you should not do is to think incrementally." You've got to think in step functions. And

I think this gives us an opportunity to re-think the loading order process and to really start off with a clean sheet of paper and really do it right. I wouldn't want to just add, you know, sort of cajole it into the existing process, I think we should really think through the whole process all over again, that's my going in thought process.

MR. GRAVELY: Other comments? Come up to the mic so everybody can hear you.

MR. CAZALET: Ed Cazalet, Megawatt Storage. I think you keep it pretty simple. It's a device that takes in electricity and returns it to the Grid, and it's got a number of megawatts and a number of megawatt hours, and that's a storage device. As we look at DR, it's already in the loading order, it's a rather complex product, and we're able to define that product well enough to put it in the loading order, so you do it the same way.

MR. GRAVELY: Okay. Thank you. Charlie.

MR. VARTANIAN: John Goodin had a great question that, if CESA is still here, would be great to respond as a group. But a couple quick thoughts and arguments for a form of incrementalism. The SGIP included storage by buying and getting to other qualifying resources. To the extent storage covers otherwise curtailed or spilled wind, could be a great argument. To the extent that it hybridizes either fuel to a case or a battery in conjunction with other fossil forms, that might be a qualifying metric, if it's going to be, let's say, classified a resource is a threshold issue. But these are just initial thoughts. I do want to go back to CESA and some other collective groups and this is worthy of a better formulated response.

MR. GRAVELY: Okay, thank you. Comment online, anybody have any comments online? Okay, so I will close up with one thought here I'd like to get some comments on, and that is, if we look at the next workshop being focused on policy, we've had these discussions, during the last IEPR, we had these discussions at several workshops during the development of AB 2514 and other activities, so, for those of you that are out there who will receive the most benefit, the providers of energy storage, or the supporters of energy storage, what policies, recommendations, or actions would you like to see us be discussing in a public forum six months from now? So, this is kind of reiteration of what are the issues that we need to address? I think I know lots of them, but it would be nice to have them on the record from those that are the Energy Storage providers that are trying to provide those services to solve their problems. So, what would you consider the key issues that we should be addressing in preparation for that policy recommendation workshop? Anybody who wants to address it, feel free.

MR. SCHAINKER: Yeah, Robert Schainker, EPRI. One of the stakeholders, and I do call them a stakeholder, is not in this meeting that I know of, is regulators. And I would suggest one piece of the answer to your question is that we need to bring some regulators into the discussion. There are just so many different legacy regulations out there, and that is based on old technologies, and we've got new technologies, a whole gamut of them, I think we need to get the regulators involved in the process of looking at these different policies. The other thing I would do, and this is because of our bad experience here in California, at least in my interpretation, is that before we make new regulations, and implement them, let's use our engineering know-how and our simulations of markets, or whatever, let's try it out on some simulations before we actually just put it into our system and then figure out did we really screw up badly, we wasted billions of dollars, before we add any regulations, whatever, pro or con, for grading these technologies, let's give it some simulation talent, I think we've got great resources here in the State of California, private as well as public agencies, and do it carefully this time.

MR. GRAVELY: Okay, thank you.

MR. RAMIREZ: If I may, Frank Ramirez, ICE Energy. It would be extremely valuable if the analysis that we did was system-level analysis. More often than not, when the analysis is done, it is site level because it is easy to understand, it is easy to measure, and it’s led to some pretty good changes in technologies. But it is only system-level effects that actually enable us to understand and to see through what the value is and a failure to look at that leads to reverse consequences.

MR. GRAVELY: Okay, thank you very much. Very good comment. In fact, I’ll share with you that part of the work that we’re looking at doing for the Vision Statement is some modeling work that CESA has been doing and been discussing with the Lawrence Berkeley National – I guess UC Berkeley. But they have some modeling capability that they apparently can help us estimate different mixtures of storage based on some modeling they’ve done for other applications, that could be adapted for storage, is what I’ve heard, so we’re trying to find that out as part of this research effort, to see if it can help us understand what type of mixture of storage would best meet the goals and the needs of 2020. Other comments?

MR. CAZALET: Ed Cazalet with Megawatt Storage again. As we put more and more renewables on, we’re moving from a Grid that was designed for fossil fuel, centrally coordinated, into something that has many many resources that are distributed, that need to be coordinated, they can’t be centrally dispatched. In fact, it’s very difficult to even control them remotely, so then what that means is you have to set up the pricing systems that the rates people receive for residential storage, for commercial/industrial storage, such that they're operated efficiently. And right now, I think everybody is kind of negative about actually moving to some kind of dynamic – fully dynamic pricing in California because of the Legislature. But, by 2020, there is room for much more of that, so if you think carefully about how do you incent the proper operation, the proper investment in storage at the right levels of the Grid, it doesn't come through participation in ISO markets, where you have to bid in storage, no end-user is going to bid into an ISO market, they are not going to bid in their Demand Response, they need to see price signals come to them that allow them to decide what to do. So, I think we've got to re-think from end to end how we interact with the ISO, how we interact with the end-users, and what those signals are, and then how we work with the Legislature and the regulatory bodies to get the right kind of pricing signals into the ratemaking, into the tariffs, that we can utilize both Demand Response as a price-based Demand Response and storage as part of the balancing of real time renewables. So, when the wind stops suddenly, and I think it is going to be much worse than what we see in the data right now, that you get that response from the combined action on the demand side, and all of the supply side, and demand side storage instantly through price signals can travel very very quickly. And without trying to second guess what is going to be there and what the right control signal will be, that's all on the client side, and through very standardized pricing signals, we can have a very powerful coordinated thing where, you know, the ISO is part of that process.

MR. GRAVELY: Thank you. Questions online or comments online? Okay – oh.

MR. GOODIN: This is John Goodin with the California ISO. I just want to second what Ed just said there, that we do believe that that is the significant part of the solution, is being able to communicate prices that reflect Grid conditions, all the way down to the end-users and the end-uses. And that paradigm is what is really going to drive and help with the further integration of renewables. Like Ed says, not everything – and this may come as a surprise – but the ISO, from the Demand Response perspective, doesn't believe that every demand resource has to be integrated, operated, dispatched, settled to the ISO market, that is not correct, the ISO believes that dynamic pricing is the solution – that's the number one Demand Response solution. Does it mean that we don't need some DR that is integrated in the wholesale market? No, we need some. The ISO is a balancing authority, and so long as the system has some level of central dispatch and control, that there is going to continue to be needs for balancing resources and for ancillary services like we talked about today. And so there will be a need for some DR that is configured in a high-quality, high reliability type of resource, gen comparable resource, from the demand side. But, again, I do second what Ed is saying. We need to advance the policies at the Legislature and the CPUC to try to get a dynamic pricing regime in place that is much more robust and must less anemic than critical peak pricing. In the ISO's perspective, critical peak pricing is the most anemic, most innocuous form of dynamic pricing, and if you have the two book ends of critical peak pricing all the way to real time pricing, the ISO wants to move and slide that policy much further to the right than remaining at critical peak pricing. It's got to move to real time pricing, or something of that ilk.

MR. GRAVELY: Okay, thank you, John. Comments? Okay, any comments online. All right, well, thank you everybody for participating today. We look forward to hearing from you. Again, those interested in participating for the next workshop we have for IEPR, check with myself or Avtar on the Vision work, and thank you all for participating. Do you have the chart that shows the address? So, on the announcement that you all use to get here is the address, we welcome comments through the end of the month, recommendations, comments, questions, information about the state of your technology if you are a vendor, again, one of the purposes of this workshop is for us to be able to prepare a document for our Commissioners as part of the IEPR to identify how the state of energy storage has changed in 2011 from where it was in 2009. And we're going to do that based on information from this workshop and what we get from those of you who participate. So, thank you all. Have a good day, and I'll see you next time.

[Adjourned at 3:45 P.M.]