BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of	) Docket No. 14-CHP-1
	)
2014 Combined Heat and Power	) Workshop re:
Staff Workshop	) Combined Heat and Power

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

MONDAY, JULY 14, 2014
9:00 A.M.

Reported by:
Peter Petty

APPEARANCES

Staff Present

Jason Harville
Rizaldo Aldas
Bryan Neff
Ivin Rhyne

Presenters

Dave Mehl, CARB
Damon Franz, CPUC
Noel Crisostomo, CPUC
Ray Williams, PG&E
Sonika Choudhary, PG&E
Joel Bluestein, ICF International
Cliff Rochlin, Southern California Gas Company
Dale Fontanez, Southern California Gas Company

Panelists

Panel 1

Tom Beach, Crossborder Energy
Cherif Youssef, Southern California Gas Company
Keith Davidson, DE Solutions
Dorothy Rothrock, California Manufacturers and Technology Association
Rizaldo Aldas, California Energy Commission
Sidney Davies, California Independent System Operator
Michael Alcantar, Cogeneration Association of California
Beth Vaughan, California Cogeneration Council
Evelyn Kahl, Energy Producers and Users Coalition
Joel Bluestein, ICF International

Panel 2

Debbie Chance, Chevron
Steve Acevedo, Regatta Solutions
David Erickson, California Public Utilities Commission
Jim Reilly, Reilly Associates
Adam Robinson, Solar Turbines
Casey Houweling, Houweling's Tomatoes

APPEARANCES (Continued)

Panelists

Panel 3

Michael Alcantar, Cogeneration Association of California
Dave Barker, San Diego Gas & Electric
Joel Bluestein, ICF International
Sonika Choudhary, Pacific Gas & Electric
Keith Davidson, DE Solutions
Evelyn Kahl, Energy Producers and Users Coalition
Bryan Neff, California Energy Commission
Cliff Rochlin, Southern California Gas Company
Katie Sloan, Southern California Edison
Beth Vaughan, California Cogeneration Council
Ray Williams, Pacific Gas & Electric

Also Present

Public Comment

Steve Uhler
Jerry Bloom, Winston & Strawn
John Larrea, CA League of Food Processors
Robert Hoffman, Occidental Energy Ventures Corp.
Thomas Marihart, Western Energy Systems
Jen Derstine, Capstone
Dan Consie, CAMS

I N D E X

I N D E X (Continued)

I N D E X (Continued)

P R O C E E D I N G S

JULY 14, 2014 9:00 a.m.

MR. HARVILLE: I'm Jason Harville. I work in the Supply Analysis Division. I'm kind of our point technical person on CHP, and I'll be, I guess, your moderator for the workshop today. I'd like to thank you all for coming out this morning, especially so early on a Monday, earlyish for me, at least.

Before we get started, I just have to give you a couple of housekeeping items here. If you haven't been here before, our restrooms are just across the hallway here if you just leave this room and veer left a little bit, they're straight across the way.

We have a snack bar on the second floor. If you go up the big staircase here, you'll be pointing straight at it when you come off on the landing there.

In the event of an emergency, we have emergency plans posted, but there's an exit right here to your left as you come out, and then the main exit to your right. If there is an emergency, we reconvene at this part, it's just kitty corner, directly across the way here, in the event of a fire or something like that, and then we can take a head count and make sure everyone is safe. And we just ask that in the event of an emergency you proceed calmly and quickly, and you can go ahead and follow us and we'll show you the way.

All right, just a couple of other items. I'm sure you've all seen the agenda. We have a pretty full day today, so I'm going to unfortunately have to be pretty strict on some of the time restrictions. I know the panelists and everyone I've already talked to, but just please do your best to stay within your time restrictions. I have a handy timer here and the state-of-the-art presenter notification system right here; black is a five-minute warning, red is a one-minute warning, you're a little far away to see the text, but I'll just kind of give you a friendly flash if you're giving a presentation or you're speaking or something, just to give you a heads up if you're running low on time there.

Okay, I'd like to thank everyone to start off with who helped put this workshop together. We had a lot of help from stakeholders from our sister agencies, and everyone who helped put this agenda together, we appreciate their help. This includes the U.S. EPA, who unfortunately wasn't able to participate directly this morning, but they did give me a brief statement they'd like me to read. And so I'll go ahead and go through that.

They say: "The U.S. Environmental Protection Agency commends the California Energy Commission's efforts to bring together key CHP stakeholders for today's discussion to tackle such important issues as CHP's environmental benefits, challenges associated with measuring these benefits, and obstacles to further CHP development. The EPA CHP partnership is pleased to be able to contribute to the discussion in the form of supporting the analysis conducted by ICF International that will be presented this afternoon. EPA strongly supports combined heat and power as a highly efficient low emitting technology through the work of the CHP partnership, its office in San Francisco and other regional offices across the country, and other programs such as wastewater management. Where possible, EPA works to ensure that new and updated Clean Air Act Regulation takes CHP's two productive outputs into account; for example, in the form of output-based standards."

So this support from the EPA and the EPA CHP Partnership is part of much broader federal support, including the President's 2012 Executive Order mandating 40 gigawatts of additional CHP nationwide by the end of 2020.

In addition to federal policy and support, California set its own ambitious goals for CHP development. Governor Jerry Brown's 2011 Clean Energy Job Plan calls for an additional 6,500 megawatts of new capacity by 2030. The California Air Resources Board's 2008 Climate Change Scoping Plan calls for an additional 4,000 megawatts by 2020. The State provides financial incentives for CHP development through the Self-Generation Incentive Program and the Waste Heat and Carbon Emissions Reductions Act Feed-in Tariff administered by the Public Utilities Commission.

California remains committed to its CHP goals in order to realize the many potential benefits that CHP can provide for our environment, economy, and energy security. Realizing these benefits requires careful and effective policy, and this is especially true with CHP. Unlike most other energy generation, CHP isn’t a single technology, instead, it’s a broad suite of technologies with an even broader range of applications. This complexity raises a number of questions: how do we identify and value the benefits of CHP resources? How do we measure the performance of a CHP system and quantitatively compare that performance with other generating technologies, including other CHP systems? How do we determine when the application of a CHP technology is a net benefit to California? Most importantly, how do we design public policy in a way that fairly compensates CHP generators for the value they provide while still achieving California’s larger policy goals and avoiding costly externalities?

Currently, CHP development in California is slow. Significant barriers still exist to the development of clean efficient CHP generation, and there’s still uncertainty on how to best identify, measure and properly value these resources. Understanding these barriers and resolving these uncertainties is essential to finding solutions. Today we hope to facilitate discussions that will lead to the solutions needed to achieve California’s policy goals.

Of California’s many policy goals, combatting climate change has been one of the most prominent. Much of the discussion today will involve greenhouse gas emissions and the common goal we all share in limiting them. Central to California’s strategy to reduce greenhouse gas emissions is the landmark Global Warming Solutions Act of 2006, known as AB 32, and the Air Resource Board’s pursuant Climate Change Scoping Plan.

In the Scoping Plan, ARB calls for cooperation between the State’s energy agencies, the Air Resources Board, the Energy Commission, the Public Utilities Commission, and the ISO. A primary goal of today’s workshop is to facilitate that cooperation and help create a more cohesive CHP strategy between the agencies. To that end, representatives from all of our sister agencies will participate in today’s workshop and we look forward to hearing from them.

To begin with, we’d like to start with the Air Resources Board. Speaking first will be Dave Mehl. Dave is the manager of the Energy

Section at the California Air Resources Board. Dave's area of responsibility includes CHP and he was responsible for the development of the first update to the State's Scoping Plan, which I just mentioned, to reduce greenhouse gas emissions. So, if you would all help me welcome Dave Mehl, please. (Applause)

MR. MEHL: Good morning. Well, our position can be summarized fairly briefly. We support CHP in general, depending upon the application. So with that in mind, as was mentioned, there's a lot of complexity to CHP, people get into it generates electricity and thermal energy, and how to acknowledge both. You know, there's a variety of fuels, technologies that are used, people get into topping and bottoming cycles. We have a much more simple viewpoint, it's one fuel use for two products. The topping/bottoming cycle, that kind of limits it to an old discussion. We want to move forward into what is a beneficial application technology, you know, if there is a technology that can do things concurrently, and has less emissions, that has a benefit in our viewpoint. It's what is the least emitting, best use of the fuel?

Quite often, people get into CHP is a natural gas technology, it’s almost synonymous; we don’t view it that way. It could be any fuel. If we are going to be combusting fuel, we should do it in the most efficient productive manner possible. And that’s regardless of where the opportunity exists.

So with that, CHP in our viewpoint has a lot of potential to reduce energy cost and greenhouse gas emissions and, again, depending on where it is, we have to factor in the criteria pollutant emissions. We don’t want to exasperate any ambient air quality problems. So we have to look at what is being displaced from the host facility.

CHP has a lot of potential because it’s being utilized where the thermal load is, and electrical loads, we have the opportunity to not continue to just put in large transmission systems crisscrossing, which have a lot of environmental impacts of their own, and risks.

So most people know about these benefits, they’ve been widely discussed, so move forward through that. It was mentioned already that we have some ambitious CHP goals for 6,500 megawatts of additional capacity by 2030, this update to the Scoping Plan reaffirmed our 4,000 megawatt commitment and acknowledged the 6,500 megawatt goal. The original estimate for greenhouse gas reductions for the 4,000 megawatts was approximately 6.7 million metric tons of CO_2 equivalent emissions reduction. That's a significant part of what the original Scoping Plan was looking to reduce. This is not a minor category. It was a significant category. And we're going after small emission reductions like SF6 from gas insulated switchgear. We're going after every opportunity and we viewed this as a real significant opportunity in the original scoping plan, and a cost-effective opportunity.

With that in mind, unfortunately we haven't seen progress in the state on CHP. It's not been going the way we would have liked in the last five years. And with that decline and stagnate CHP development, we're not getting the emission reductions we had anticipated. As was mentioned by Jason, there are significant barriers to CHP still, and in the updated Scoping Plan, we have a measure that ARB is going to lead an assessment of those barriers and propose ways to address them. We will be starting that assessment soon and there will be a public element to that process. We will be working with the other State agencies on that. So it's going to take us a while to work together, get the public process moving, and really come out. But in a timely manner? We hope to have that totally done by 2016, that's what our commitment was in the Scoping Plan. And I think we have as an agency fully committed to that, and we're going to put the resources on it to address these issues.

And one other thing that the Scoping Plan did mention is that, if we don't see progress, we do reserve the right in the Scoping Plan to pursue a measure to -- basically it would mandate. Now, that becomes a complex issue regarding siting and some other things and there might have to be some legislative action and some other things, but that's something that will be coming out probably of the assessment and the potential solutions. And one element that is still important is there is still a significant potential for CHP in the state. Now, you know, one thing I would like to throw out is this is not a sanctioned Board policy, this is staff viewpoint, but some of the things are that we need to support the most efficient form of electricity generation and thermal production, and a lot of that has to do with siting. We need to site power plants where there's an opportunity to combine the effectiveness of CHP with where the load is. And combined cycle power plants still have enough heat residual in the exhaust to drive most thermal lodes. So it's about siting –- you can have CHP and you can have your combined cycle and still be beneficial and improve the overall efficiency, it's not a one or the other necessarily, it's about siting where it fits for the grid, where it fits for ambient air quality standards, and where there's a thermal load.

Also, getting back into the barriers, we need to address how to site these, the permitting process, interconnection, non-bypassable charges, all of the issues that we've been talking about since I was first pulled into CHP, which was about six, seven years ago. We need to really address this in a cohesive comprehensive manner. We have to get in and really figure out what is best for the state long term. We’re still siting natural gas power plants, so if those are going to be here for 30 years, why not do it in the most effective manner possible? So I will keep it short just to keep things moving. If anybody has any questions, feel free to contact me.

One other thing I was reminded of on the walk over that I should bring up, with regards to the Scoping Plan, part of the Board’s resolution is that we go back to our Board annually and give an update on all the measures that were in the update as far as how progress is being achieved, if there is progress, what are the issues? So this is going to be something where our Board is taking action, going to be hearing annually on every measure including CHP progress, and they are wanting us to be -- with the document -- not be something that everybody comes and says, “Oh, it was a good document,” and then gets shelved for five years. They want to see action. They want to see these issues actually get addressed. So with that, Jason, back to you.

MR. HARVILLE: Thank you, Dave, appreciate it. Okay, so we’re going to move on now to our first panel of the day. This panel concerns the values and benefits of CHP and the potential benefits they can provide to California. I understand greenhouse gasses is a large issue and we're going to hear a lot about that this afternoon, so this panel is primarily concerned with the potential benefits beyond just fuel efficiency and, you know, the corresponding greenhouse gas reductions whenever you have any fuel savings.

So we're going to have the panelists hopefully discussing other benefits, maybe benefits that are undervalued or not properly valued, or could be valued in a different regulatory environment, as well as possible technological changes and advancements that could bring new benefits from CHP to California.

We're going to begin this panel with some individual statements and presentations with panelists highlighting some different values of CHP that they see as important, and then we're going to follow it up with a general group discussion of these values, and following the questions as you've seen on the agenda.

So to begin, I would like to start with Tom Beach. Tom is a principal consultant with

Crossborder Energy and the Technical Consultant to the California Cogeneration Council. Tom has been a private consultant in the Energy Industry since 1989 and prior to that he spent eight years at the CPUC as an Advisor to three Commissioners, and worked on the initial implementation of PURPA in California. Tom has worked actively for his entire career on CHP and Distributed Generation issues in California and other states. Tom?

MR. BEACH: Thank you, Jason. I'm happy to be here and I appreciate the Energy Commission holding this workshop today. If we go to the first slide, what I'm going to talk about are five benefits of CHP that are not reflected in the price that CHP projects are paid for the power that they export to the grid.

I think as many of you know, the avoided cost price that's paid to CHP projects, you know, they're paid for their energy, they're paid for their generating capacity, and they're paid to the extent that they reduce line losses on the transmission and distribution system. But there are other benefits of CHP that have been talked about, many of them have been talked about for a long time, but really very little action has been taken to incorporate those benefits into the economics of CHP products in the state.

So I'm going to go over five of those benefits, there are six listed here, the last one is supporting California's manufacturing, industrial, commercial, and institutional customers, and I'm not going to go over that one, but that is one that is very important to the CEC and also to the Co-Generation Association of California and the Energy Producers and Uses Coalition on whose behalf I'm also speaking today. But we'll defer to the CMTA presentation on those important economic benefits.

So the first benefit I want to talk about is avoided transmission costs. If we go to the next slide. Now, this is something that I think certainly for CHP that serves an onsite load without the use of the transmission system, it is certainly acknowledged that onsite generation will avoid transmission costs. But CHP that is located in the load center, and that exports to the grid, also can avoid transmission costs, and I think the only place in which this is recognized is for the AB 1613 program for small CHP under 20 megawatts, there is a 10 percent adder to the price that those projects receive if they're located in local capacity reliability areas, in other words, close to loads. And to some extent TND benefits have been incorporated into some of the CHP planning studies like ICF used the $50.00 per kilowatt year, TND deferral cost is one of the benefits in the work that they've done for the CEC. And I think that it's also generally recognized that if you look, for example, at large scale renewables, everybody realizes that those resources have significant transmission costs associated with bringing them into the load center.

But beyond the one recognition in the AB 1613 pricing, avoided transmission capacity costs have not been included in the prices paid for CHP generation in California. The numbers are out there and I present them here in the table in terms of the marginal transmission capacity costs that have been calculated in a number of IOU general rate case filings, and demand response filings. Obviously the costs that are avoided depends somewhat on where the CHP project is located and at what voltage it is sending its power into the grid, whether it's avoiding just

ISO high voltage transmission, or whether it can also avoid some of the IOU sub-transmission costs, as well.

But these are real marginal costs and we think they need to be included in the payments that CHP projects receive for their power. So next slide.

I think that, as Dave Mehl just said, sort of a foundational reason that we do CHP is because it's a more efficient way to serve both an electrical and thermal need, it's kind of the fundamental premise of CHP. There's been a lot of -- some debate recently about exactly how efficient CHP is in California, and the extent to which it produces greenhouse gas savings because of its efficiency, and this is a graph in a format that PG&E, I think, is going to use in its presentation this afternoon, and so we did a version of it. It plots the electricity output per unit of fuel input on the horizontal, and the useful thermal output on the vertical, and the more efficient a project is, it's going to be in the upper right on this graph, and if it's less efficient, it's going to be in the lower left. And the straight lines are the various double benchmark efficiency standards for CHP, the red line is the double benchmark in the CHP settlement from a couple years ago at the CPUC, an 80 percent efficient boiler and a system heat rate of 8,300 Btu's per kilowatt hour. The dashed blue line is a double benchmark with somewhat lower system heat rate, I think that's the projection from the E3 consulting firm for 2020.

And we plotted on here a number of the existing CCC and CAC members, and you can see that they're all above these double benchmarks. I also put on there, I think, five new CHP projects that our firm has done feasibility studies for over the last several years. Unfortunately, for a variety of reasons, only one of these projects has been built. And you can see that they all are on the right side of the double benchmarks.

Now one of the issues, PG&E has a double benchmark that is further to the right of the one shown here, and that is based on an assumption that CHP will be avoiding renewables; in other words, if a CHP project serves an onsite load, it will reduce the utility sales, and the utilities will then be buying less renewable generation because their RPS target is a function of their sales. And under this argument, the system power that CHP avoids would be 33 percent carbon-free, and would make a higher hurdle for CHP to show GHG benefits in California. Well, our perspective on that argument is that I think the Legislature settled it last year when it passed AB 327, and one of the key elements of AB 327 was a decision by the Legislature that the RPS is no longer a cap on the amount of renewable generation, but it’s a floor on the amount of renewable generation. And the Legislature made that very clear in that law. And if the RPS percentage is no longer a cap, then a reduction in sales no longer means that the utility should buy less renewable power, and we think that kind of removes that argument about the GHG reduction benefits of CHP. Next slide.

This benefit is one that’s been discussed for years and that is that, when an onsite generation serves load, it reduces demand on the grid. And what this is, it’s a supply curve for the California ISO market. This was prepared by EtaGen who is a developer of small CHP technology, and they have done some really interesting work on this particular benefit. The concept is very simple: if you reduce the demand on the grid, you shift the demand curve to the left, and you reduce the market price of power in the California ISO market, and that has benefits that extend across the whole market because everybody gets paid the market clearing price. The same argument can be made for infra-marginal CHP generation that's put out onto the grid, that shifts the supply curve to the right and also reduces the market clearing price for power. EtaGen calculated a benefit of about $20.00 per megawatt hour from onsite generation reducing market prices in the state, and this is actually an idea that other states have put into place. In New England, the costs that are used to evaluate energy efficiency programs include this effect, and it results in about a 20-25 percent increase in the avoided costs for demand-side programs in New England. Next slide.

This is a slide that I took from a recent report by GreenTech Research on Microgrids and Microgrid development in the U.S., and what's immediately apparent if you look at this picture is that sort of the epicenter of Microgrid development in the U.S. is in the U.S. Northeast. And that's a result of the impacts of Super Storm Sandy a couple years ago, which really brought home to that region of the country the fragility of the electric grid and stimulated a lot of interest in institutional and military and government customers in taking action to increase the reliability of their electric service by pursuing Microgrid developments, you know, a Microgrid is basically a small grid that can island from the major grid in case the major grid goes down.

You can see that the interest is largely from universities and research campuses, the military, and various governmental entities that have the kind of concentrated load that can be served from a Microgrid. Now, a lot of these Microgrid systems, CHP is sort of the foundation of the generation that's used because it's base load, it also provides any thermal needs that the site has, and it's highly reliable.

So I think that this emphasizes sort of the new focus on reliability and resiliency that is happening as other regions of the country are experiencing significant and prolonged grid outages. Now, putting a dollar value on improved resiliency is not an easy thing to do, but there are some studies that have tried to do that. The Solar Energy Industries Association did a study in Pennsylvania and New Jersey that put a value of about $20.00 per megawatt hour on the enhanced reliability from distributed generation.

And the final slide I have, and the final benefit addresses the issue of how CHP fits in with the very ambitious GHG reduction goal for 2050 that California has, and that goal is an 80 percent reduction compared to 1990 emissions. I know the ARB Revised Scoping Plan discusses some of the academic studies that have been done on what we're going to have to do to achieve that goal, and I think they all conclude that we're going to have to electrify multiple sectors of the California economy. In addition to electric utilities we're going to have to electrify transportation and buildings and a significant fraction of the industrial sector, as well. And so in that context, to the extent we're going to be using fuels in 2050, it's very clear that they're going to have to be used as efficiently as possible, and CHP allows two products to be produced from burning fuel a single time, and in addition, in 2050 we may have different kinds of fuel, it may not be natural gas, it may be biomethane, hydrogen, fuels that are much more expensive and less available than natural gas. And again, in that context we're going to have to use those fuels as efficiently as possible and CHP seems like it's going to be a natural in that environment to the extent we are using fuels.

And finally, a lot of the work that's been done, for example, the E3 study that was done recently on 50 percent RPS for California has highlighted the need for an electric generation mix in 2050 that is as diverse as possible. It's going to be harder if we put all our eggs in one basket, for example, that study shows that there could be issues if we try to get to a 50 percent RPS just using solar and emphasizes it will be a lot cheaper to integrate renewables if you have a diverse mix of them. And I think that applies to all types of generation resources. We need base load as well as flexible resources, and so especially if we're phasing out coal and maybe even nuclear generation in the future, there is going to be a need for base load generation such as what CHP can provide. I also think that it’s pretty clear that customers themselves are going to want a much bigger say in where their energy comes from and in producing it themselves, and CHP is also going to be an important part of customer choice, I think, in the future as we move towards 2050. So thank you.

MR. HARVILLE: Great. Thank you, Tom. The next panelist I’d like to introduce is Cherif Youssef. Cherif is the Technology Development Manager for the Southern California Gas Company. He has 38 years of experience in the energy industry, with past responsibilities in marketing, human resources, operations, and engineering. Cherif is responsible for managing a $10 million per year R&D program focused on developing and demonstrating new technologies that help improve energy efficiency, meet environmental regulations, use renewable energy, and use alternative fuel vehicles. Cherif has a Bachelors and Masters in Electrical Engineering from the University of Southern California. Thank you, Cherif.

MR. YOUSSEF: Good morning. Thank you, Jason. I appreciate the opportunity to be part of this panel and part of this workshop. You can move to the next slide.

SoCal Gas has been involved with CHP for many years, we've been participating with the California Energy Commission on several technology developments, the most recent one is related to engine development to meet the CARB emissions requirement for NO_x and CO. We also partnered with them on several technology demonstrations, the use of a micro turbine and an absorption chiller at a data center, the use of a micro turbine and a boiler at a food processing facility, the use of exhaust heat in a CO_2 recovery for use in a greenhouse gas nursery facility, also the use of waste heat from metal heat treating furnaces to produce electricity, and finally the use of onsite generation for electric generation for water pumping applications.

SoCal Gas has been involved in many feasibility studies over the years, and we continue to provide many education and seminars and training to our customers at our facility in

Downey, California. Next slide, please.

This is a couple of charts from an ICF study that was conducted for the California Energy Commission, and I believe Joel Bluestein is going to talk about this a little bit more, but I thought I would like to highlight a couple of things from that study. The first point on the chart at the top left is the slow growth of CHP capacity in the U.S. and California over the past 20 years, specifically in the last 10-15 years. Even with the addition of proposed 4,000 megawatts by 2020 as part of the Scoping Plan and the Governor’s plan for 6,500 megawatts by 2030, we’ll still fall short of the State plan to achieve greenhouse gas reductions. However, we think there is significant potential for CHP in the state between now and 2030. I think the ICF study estimated the potential to be about 16 gigawatts for CHP sizes less than 20 megawatts. So the potential is greater than the market trends have indicated, it’s a very large untapped resources exist for many energy intensive industries and businesses. Next slide, please.

The next three slides basically try to address those three questions that were given to the panel. The first one is the value of benefits of CHP. First, obviously clear is the use of natural gas as a clean, reliable, affordable energy source, as well as abundancy. Second here is the available new technologies to meet these strict emissions requirements for the state, not only CARB's requirement, but also the local Air Districts such as the South Coast AQMD and San Joaquin Valley to meet the tightest emissions requirements for NO_x and CO.

The potential to achieve cost reduction for Micro-CHP similar to PV, we all know the PV prices and costs have come down the last few years, and obviously it is a renewable source, but for Micro-CHP, we see also great value as being able to offer a continuous deployment form of energy, higher efficiencies, and also to be able to integrate easily with the electric grid. The utilities have been involved with promoting CHP, developing technology and demonstrating technologies to continue the evolving benefits of CHP, as well as the ability to use waste heat more effectively. Many other countries have been involved and I think they may have had some tremendous success, countries such as Germany in the United Kingdom and Japan, Japan has been heavily involved in demonstrating .7 KW fuel cell, but it's happened because of huge incentives being offered, but they have quite a bit of Micro penetration.

The CHP can help California meet several of its key energy policies and goals, it can certainly help meet the energy efficiency and demand response goal, it can certainly help meet the greenhouse gas and criteria pollutants reductions, as well as energy security, can achieve all of these goals.

Finally, the removal of San Onofre and once-through cooling, it would leave the state with about over seven gigawatts of generation deficit. CHP was identified by the CPUC as a preferred resource in their Preliminary Reliability Plan for L.A. Basin and San Diego. Next slide.

This slide addresses the value of development and deployment of CHP. Utilities, gas utilities and other electric utilities also need to adapt and evolve to emerging technologies and the policy trends. The great benefit we enjoy today in directive spark spread between natural gas and electricity offer a great opportunity to promote CHP.

California Executive Orders are not adequate, at least as we see it today, not supported by several directives on regulations. For example, increasing incentives specifically for the self-gen program to include Micro-CHP and expand the use and incentive for that application, the offering of tax credits and appreciation, actually that appreciation to be equal to other renewable sources such as PV and wind, reduce the first cost of CHP by streamlining all the additional costs associated with permitting and air quality applications. More innovations are needed in order to move this technology forward, and I'll talk about that a little bit more in my next slide. Also to increase the awareness to support the key state policies for energy efficiency and demand response, RPS, energy storage, and others.

And finally, we will need to make sure that policies and regulations don't discourage CHP, and let me expand on that a little bit. Most customers will elect to remain grid connected. Emerging technologies will allow wider choices of products and services, and Smart Grid will eventually feature Plug-and-Play interconnection of onsite generation. In order to achieve all this, I think the electric utility needs to be actively engaged in helping and enabling that, eliminate excessive departing load charges, and also be involved in the growing issues and resolving the issues related to interconnect that might create issues with grid stability, voltage regulation, and safety. Next slide, please.

This slide addresses the technology, future technology research needs. Being from Southern California, as we all know, the South Coast and San Joaquin Valley will continue to require emissions reductions, I think they plan to have 80 percent NO_x reductions by 2023 target to achieve ambient air quality standards for ozone. We need cost-effective products specifically for Micro-CHP, and I'm talking about small scale, and you know we haven't discussed sizes yet, but I think we're talking about maybe different sizes for different markets. If I may, I think we need sizes for residential market between 1 and 5 KW, for multi-family 5 to 25 KW, commercial application 25 to 200 KW, and then for industrial applications, over 200 KW, so each one of these market targets require different products.

I would like to see Micro-CHP that achieves higher efficiency, electric efficiency, be able to run independent of the electric depend of the facility to maximize the use of thermal load, to provide high water and space heating for onsite use, as well as the possibility to provide space cooling. Absorption chillers are available today, double-effect, triple-effect, but they’re not cost-effective. I think we need to do more research in that area to make it more appealing. Use of waste heat, bottoming cycle specifically, I think that’s a technology, again, the product is available today, but not yet widely used.

Finally, the two comments here is we need to look at integration of onsite generation and renewable. And I’ll talk about that more in terms of ZNE or Zero Net Energy, how that could be possible. Next slide.

This is a concept, really, of a smart home, Zero Net Energy Home, and for those of you who have asked me what ZNE is, I can simply define it as the onsite net energy consumption and production over a year to be equal to zero. How is that going to happen? Well, the first way we can achieve that is to develop smart and most efficient appliances so we can reduce energy consumption in the home, second will be by installing some kind of renewables, solar PV or solar thermal to be able to take advantage of renewable energy, the third piece would be the onsite generation of something like Micro-CHP, and to be able to use the waste heat, to integrate that into the energy needs for the home, such as hydronic heating, and to make all of this happen we need smart controls and to be able to integrate all of these pieces and ability to provide the homeowner with the ability to use all of these devices well. Next slide.

So my conclusions are, California needs a robust implementation plan to realize the environmental benefits of CHP, we need to remove the barriers, the barriers are the energy rate, the perceived instability of gas and electric rates, the technical complexity of CHP by maybe potentially pre-qualifying some of these systems, to remove some of the hurdles, reducing the costs associated with permitting, and specifically maybe in some cases air quality benefits, air quality permitting in Southern California, the customer’s preference to integrate renewables with onsite generation, lack of customer awareness on the value of CHP, especially small customers if we talk about small commercial customers may not understand the full benefits, all the interconnection challenges both from the gas and electric side, lack of financing, faster depreciation, and tax incentives to offer similar to what’s being offered to renewable PV and wind.

I think incentives are still going to be important to help promote CHP, why they’re used, but we recognize the outlook is encouraging, however, we need proactive legislation and energy policy to meet our goals. Thank you.

MR. HARVILLE: Thank you, Cherif. The next panelist I’d like to introduce is Keith Davidson. Keith is the President of DE Solutions, Incorporated, a consulting and engineering firm serving the distributed energy markets. Keith is formally President of Energy Nexus Group and a Senior Vice President at Onsite Energy Corp, where he had regional responsibility for energy services and oversaw the consulting practice. Prior to onsite, Keith was a director at the Gas Research Institute where he led programs directed at electric power generation, cogeneration, gas cooling, and industrial process improvements. Keith has more than 25 years' experience in energy and environmental technology development, project management, product commercialization, feasibility studies, application engineering, economic analysis, and market development. He was past President of the American Cogeneration Association and served as Chairman of the National Association of Energy Service Companies' Distributed Generation Committee. Currently, he is active in the California Clean DG Coalition and the Association of Energy Engineers. Keith.

MR. DAVIDSON: Thank you, Jason. Thanks to the CEC for hosting this workshop. I have no slides, but as Jason mentioned, I'm a member of the California Clean DG Coalition, and the agenda defines small CHP as less than 20 megawatts, that pretty much defines the membership of the California Clean DG Coalition, so our perspective is going to be on the smaller side of the CHP market and the next panel actually delves into some of the issues in that market, into more detail, so I’m going to have some fairly brief remarks here today.

But Combined Heat and Power, which has been around for a long time, I mean, it’s a silver bullet, it’s been, its overall efficiency, ability to use thermal energy, and it’s been the key to probably the number one driver of CHP over the years and I think still today, which is economics, you’ve got to use the heat, and we feel that the inventory of CHP in California and throughout the rest of the United States, there’s a large majority of CHP systems that fit that metric and I think that, you know, there’s been some examples of some systems that weren’t designed properly, weren’t operated properly, weren’t maintained properly, but I think all in all CHP has a very good track record and is capable of efficiencies in the 70 percent plus range.

And there’s a bunch of ways that that CHP can achieve those kind of efficiencies and one perhaps most obvious is to size the CHP system to meet the base load thermal load, but that’s not the only way, you can operate your CHP system to thermally load follow, and there's a lot of examples of systems out there today that do that. And some of them as simple as if there's a heating load you turn the CHP system on, if there's not a heating load, you turn the CHP system off. And a lot of these systems don't have any ability at all to reject heat to the atmosphere, or to some other dump load, so you're either using the heat, or your system is shut off, and then there's really no way but to get those kind of higher efficiencies when you have a system like that.

And then another way to get the high overall efficiencies is to include thermal energy storage, whether it be hot water, a hot storage, or a cold storage mechanism, and there's some examples of that around where you can use your thermal energy storage to fill in the diurnal peaks and valleys of your thermal load. And Cherif mentioned another one which is you can add absorption cooling, so there's a way to actually create additional thermal loads, which makes sense for some applications.

I wanted to mention that CHP is very

ready and easily adaptable to provide other benefits that have been discussed, and one of them is emissions, low emissions, low greenhouse gas footprint, and the low greenhouse gas footprint is linked directly to high overall efficiency, and CHP systems also with the right kind of interconnection scheme are very capable of providing local resiliency and reliability to either a single host or a Microgrid, which could be a collection of facilities. And on Microgrids, the ones that I've seen, CHP typically isn't the only answer, but to the extent there are thermal loads that can be tapped into using combined heat and power as sort of a base load foundation for the Microgrid, it makes a lot of sense and we're seeing some examples of that developed in California and around the United States.

The other item I thought I'd mention in this panel is the long term procurement plan that the CPUC has and specifically its mandates or its targets for Southern California reliability area, namely the West L.A. Basin and San Diego County, and a requirement to use a certain amount of local capacity resources, and with an emphasis on preferred resources, of which CHP is one of them, and we were happy to see that.

There was an initial RFO that went out of SoCal Edison last quarter of last year, and I can't say I'm an A student in what happened there, but I noticed that there were a lot of different ways that people could bid in for the resource requirement, and they had energy efficiency, it had demand response, and it had a variety of supply-side resources for sale back to the utility grid. And the one resource that seemed to be missing was onsite CHP, which in many ways is akin to energy efficiency measures where the customer sees the benefits of CHP and has the ability to ask for additional payments from the utility, not much presumably, but some payments to make the hurdle rate for the efficiency investment more in line with the hurdle rate for non-core investments at the various post-site facilities. And we don't see why CHP shouldn't be given the same kind of opportunities, and we hope that future RFOs for local capacity resources that are due out presumably this year or next year do have that capability, or do enable onsite combined heat and power to compete in that marketplace. And with that, let me just maybe make one comment about long term, I mean, in going out towards the 2050 goal, Tom I think addressed this very well, but you know, CHP and the fuel used in CHP is going to have to adapt at some point along the road to 2050 to either not be a 24/7 base load operation, and CHP can do that, it can be turned off during certain parts of the day when you’ve got over generation capacity from solar and also the de-carbonization of the pipeline system that is now used for natural gas can be used for biofuels and some hydrogen. So I don’t see that natural gas CHP today necessarily precludes that same facility to reconfigure itself and adapt to a changing California landscape. And with that, I’m going to conclude my comments for this session. Thank you.

MR. HARVILLE: Thank you, Keith. Our next panelist is Dorothy Rothrock. Since 2000, Dorothy has been a Lobbyist for the California Manufacturers and Technology Association, a statewide trade association representing the largest and smallest manufacturers doing business in California. Dorothy began her career as an attorney for Portland General Electric working on customer relations, rate cases, wholesale power contracts, and government affairs. Dorothy.

MS. ROTHROCK: Thanks, Jason. And I'll change it up here a little bit. I just want to give everybody here kind of a snapshot, a little bit of context for what it's like to be a manufacturer in California. Of course, manufacturers are hopefully some of the major thermal loads that would be embracing CHP, and so it's good to understand what they're facing in California, the kinds of decisions they're being faced with, and the environment in which they're operating.

Of course, manufacturing is very important to California as a sector of the economy. We're still the largest industrial state in the U.S., but we have huge challenges with the cost of doing business, and I'm not saying anything that folks don't know -- high taxes, work comp, energy prices are very high, so there's challenges that we have beyond energy, but yet those issues influence our energy decisions.

Of course, making sure that manufacturing survives and grows in California is hugely important because of the multiplier effect for manufacturing investments and jobs. One manufacturer supports anywhere from two to five other jobs in the rest of the economy, depending on the type of manufacturer, tax revenues, highways jobs with good benefits, you all know this, manufacturing is the most important sector of the economy. I'm slightly biased.

But the environmental issues are very important, as well. Since climate change is now the overarching environmental issue that we're facing, making sure that manufacturing in California can not only survive, but also grow, is very important to minimize leakage because if we continue to have high costs that pushes manufacturing out of the state, then of course emissions will rise in other places in the world such as China or India, where the energy supply is much dirtier, and we will frankly be going backwards in our efforts to deal with climate change.

Okay, let's move to some slides because I just have three slides here to give you a little bit of a sense of what I'm talking about here.

This is the latest as of April kilowatt average industrial rates in some select states, including California, and you see that we're still very high. And I think I usually say in testimony at the Legislature, we're on average 50 percent higher than the rest of the country. Over the last few months that I've looked, it's more like 60 percent. It seems that the rest of the country is trending either flat or a little bit lower with the natural gas boom, California is staying a little bit high, or maybe increasing a little bit, I don't know what all the ingredients are, but the trend line is moving even more so in a less competitive direction. Next slide.

This shows the growth in jobs since January 2010 in which we count the end of the recession and you'll see California is moving along kind of up and down, but generally flat since then in terms of manufacturing job growth. The rest of the U.S. has had a nice bounce back, 5.5, 6.0 percent, and I think there is a fair amount of industrial growth going on in the U.S. because of the natural gas boom, and there is a renaissance, a re-shoring effect that's happening because of the cheap energy where manufacturers for a lot of reasons, not only cost, but logistics and customer demand, are deciding to go ahead and locate back into the U.S. where they might have in prior years maybe expanded elsewhere. So there's an opportunity for California to grow along with the U.S. in the coming years, and so if we can step up and fix some of our problems, and address some of these challenges, we could do it. Next slide.

This is a very alarming slide. We've got a few others like it, but this is the only one I picked. This is last year's capital investment rate in California compared to the rest of the country, and those are all other states, those other bars are other states. The point is that, on a per capita basis, we're only getting 1.5 percent of U.S. manufacturing investment. These are new or expanded sites. We have 11.4 percent of U.S. gross state product, but last year our investments were only 1.5 percent. So we're not maintaining kind of -- we ought to have 11 percent of the U.S. investments on a year to year basis if we want to sort of sustain what we have here. But I think the only states lower than ours are Maryland and Hawaii. That's my last slide.

I did want to mention a few things. We've heard a lot about the benefits of CHP, but in this context, noticing the challenges we have and the cost issues in California, what's really important about CHP is that it is a tool for manufacturers to use to manage their energy use. Also, a commitment to CHP I think creates kind of a sticky effect for a manufacturer in the state, it's a commitment that's longer term in California, and if we can make it easier for manufacturers to embrace it, I think we'll stand a better chance of keeping them around. Also, there's now a new alternative to CHP or efficiency, and that is the allowance market in cap-and-trade, so we have some alternatives and proxies for what it will cost a manufacturer to survive in California with CHP as an efficiency matter, alternate, you know, renewables, or purchasing allowances in the cap-and-trade market. So as cap-and-trade prices, allowance prices rise over the coming years, and particularly as we're heading into potentially 2050 with a cap-and-trade market, there's going to be more and more opportunity for CHP to be a solution because the alternatives may be much more expensive, and the more the barriers can be addressed sort of in advance of that, the better we'll be able to transition folks, as opposed to having these hurdles being as big a barrier, if not more of a barrier than they are now.

I think that the only other issue is that, and Keith touched on it, too, is that since so much of the new CHP is likely to be in smaller manufacturers, they're not as sophisticated, they're not as able to deal with the barriers. I mean, a short barrier for a large manufacturer is a big barrier for a small manufacturer, so we may need to get down to even a lower level of barrier identification to find those even, you know, one-foot level barriers, to make sure those don't keep some really good projects from being done, just because the folks are saying, "Oh, I can't deal with that, I'm running a business, I'm the only guy here, and I don't have anybody that I can pass this off to in my staff." So with that, I'll finish.

MR. HARVILLE: Great. Thank you, Dorothy. Next up we have Rizaldo Aldas. He is the Program Lead for the Energy Commission's

Renewable Energy and Advanced Generation RD&D Program which supports research and development on combined heat and power, among other technologies. Rizaldo has been with the Energy Commission for over five years, primarily working in the Energy Research and Development Division, and Rizaldo received his PhD in Biological and Agricultural Engineering from U.C. Davis. Thanks, Rizaldo.

MR. ALDAS: Thank you, Jason. Good morning. We are talking about values and benefits of CHP and we have heard a lot of these from previous speakers, I'm not sure I can add more to that, but my task here is to provide some perspective from the RD&D, specifically provide examples of R&D demonstrations, demonstrated benefits, and opportunities that could help further the development of combined heat and power in California. Next slide, please.

So just before I go now, I just want to mention a little bit about our program. Our RD&D initiative related to Combined Heating and Power is part of our Renewable energy and Advanced Generation, which is a component of a larger energy generation research. Our goal is to help advance the market penetration of CHP, help achieve the goals that were mentioned a while ago, like the Governor’s Clean Energy Jobs Plan, the goal under the AB 32. And we implement initiatives that are publicly vetted from these stakeholders. Next slide, please.

Now, in order to fully benefit from Combined Heat and Power, we will need to address a lot of challenges and issues. We have heard a lot of this from previous speakers, too, and there are many of them. What I listed here are just some of the technical challenges. These are known to many of us, I think, one of the important things here is the ability to meet the state and local area emission requirements in light of the ARB Emission Standards, the Local Air District requirements such as the SCAQMD’s Rule 1110.2, and this particular challenge I think brought a lot of developments in the clean emerging generation, we have heard of the fuel cell, for instance, and in the emission control technology for traditional generation technology such as the reciprocating engines.

We have abundant opportunities for renewable and alternative fuels, so there’s an opportunity for that, for flexible systems, particularly in biogas or biomethane, due to current requirements for increased renewable in California. I think there are also opportunities for systems integration of advanced generation technologies relative to integrating Microgrid, as we heard from the first speaker and, you know, I believe that with appropriately developed controls, I think CHP will play a major role in Microgrids.

I think overall there is room for improvement, for improving the performance, lowering the cost, and again, lowering those improvement performance, lowering the cost in order to fully benefit for combined heat and power.

In terms of the innovations, I think the technology developed and currently being developed are cutting across these several issues and challenges. And what I have listed here, just examples of the technologies, the innovations, both developed, both completed, and both ongoing, I will not be discussing all of these, I will discuss a few of those, but if you have any questions, feel free to contact me, I provided the contact information on the last slide. So if you would go to the next slide, please?

Now, the first example that I would like to provide here is the innovation on the Hybrid Partial Oxidation Gas Turbine and Internal Combustion Engine, Combined Heat and Power. This technology is being developed and it is going to be demonstrated in the City of San Bernardino, the project is receiving a lot of support from a variety of entities including the Southern California Gas Company, the South Coast Air Quality Management District, the City of San Bernardino, and others.

This particular technology and innovation will address both the emissions challenges, the cost issues associated with some of the alternatives for emissions control like the Catalytic Reduction Technology, and I would say this is positioning the technology for anticipated emission requirements in the South Coast Air Quality Management District. So in very short description, the diagram is provided at the right, basically the Partial Oxidation Gas Turbine (POGT-ICE) Hybrid System will take in some of the biogas produced by the wastewater treatment facilities, use that biogas to produce hydrogen rich gas, which will then be combined with the Biogas stream. That will allow the internal combustion to operate in a lean condition, basically addressing the NOx requirements, and in the process generate additional electricity coming from the Partial Oxidation Gas Turbine, and that will add to the generating capacity of the existing internal combustion engine.

Once completed, some of the features of this approach is provided here, be able to use a biogas or natural gas for hydrogen production, it will allow additional requirements for biogas or natural gas cleanup, and will provide additional electrical energy, again coming from that gas turbine system.

Now in the next slide, I just wanted –

MR. ALCANTAR: Quick question. What is the size of that test facility?

MR. ALDAS: Well, the Partial Oxidation Gas Turbine is sized for 65 kilowatts, but the existing Internal Combustion Engine is a 750 kilowatt system.

Now, I just want to introduce briefly the conceptual basis for the Partial Oxidation Gas Turbine. I have mentioned that the Partial Oxidation Gas Turbine can produce hydrogen rich syngas, hydrogen rich biogas, and so that concept is based on what is called the Hydrogen Assisted Lean Operation, or HALO, and that HALO refers to adding certain percentage of hydrogen through the fuel stream to allow the reciprocating engines to operate in a lean condition. There are already numerous studies done on HALO; at the Energy Commission way back several years ago we supported the project on the Bio HALO, for instance, and then we have an upcoming project with the GTI Corporation looking at producing hydrogen from biogas and to be able to use that for a gas engine. These studies have demonstrated benefits in terms of NO_x reductions, some have shown increased efficiency in wide scale engines, large station engine, small units for co-generation. Now, the challenge here is to cost-effectively supply the hydrogen when this is being addressed by this project.

The next example that I have in the next slide addresses the opportunity for technology integration cost issues, and NO_x emissions, and this one is focused on integrating Microturbine with existing boilers. This specific project engineered and integrated a simple cycle gas turbine with an innovative boiler burner, so the system was first tested in the Altex facility in Santa Clara, and then field demonstrated in Westin Hotel in Costa Mesa. Some of the benefits from that project included providing additional electricity generation, 100 kilowatts from the Microturbine, meeting the thermal need and producing power, and for that particular project the projection was about six and a half cents per kilowatt hour, and meets the emission limits both in California, particularly in Southern California.

The next example that I have is a similar goal, addressing similar challenges in terms of integration, addressing cost and NO_x emission issues, but differs slightly in terms of the approach. This project is developing, or it just developed, a cost-effective gas turbine based combined heat and power system that meets emissions standards without the use of catalytic exhaust and gas treatment. The project in particular, as you can see in the diagram, integrated a Capstone C65 Microturbine and innovative supplemental burner and boiler, it was validated in a GTI facility and then fuel tested in a food processing facility in Riverside, California, and the results are shown in the right portion of the slide, basically the tests demonstrated the benefits in terms of increased efficiency, meeting the ARB emission requirements.

Now the last example that I will provide to you here in the next slide is our brand new project with EtaGen, it is an emerging technology, it was awarded in our most recent natural gas solicitation. The goal for the project is to develop and test an advanced high compression ratio homogenous charge compression ignition engine, a Free Piston Engine. It basically features a new engine architecture, as you see from the diagram there, it is kind of moving away from the limitations from the traditional reciprocating engine. You may imagine a traditional reciprocating engine with a rotating shaft and from the diagram this is kind of introducing a linear piston arrangement and electricity generation combined in the system. So the Clean Piston technology will enable the expansion of operation, will introduce ultra-low emissions, and cleaner and simple engine. The diagram at the right is providing the difference in terms of what can be achieved in the compression ratio between the traditional or conventional engine and the proposed technology.

All right, the next slide is kind of straight from the proposal and the scope of work for this agreement. Basically this is just to show you some of the specific targets for the project like they're looking at providing the more than 50 kilowatts of system being able to demonstrate the high efficiency both from the thermal and electrical, being able to demonstrate a certain high number of hours, and I also provided some of the commercial performance goals being targeted by the project.

Okay, with that, I just want to introduce to you in the next slide some of the upcoming opportunities from our program. These are some of the R&D initiatives that were kind of published, we put out in a public workshop for the natural gas budget plan. In our '13-'14

Natural Gas Budget Plan, we have two areas there, one is on improving the biomethane/biogas, which is also in the Distributed Power Generation. The other portion of that is on the bottoming cycle, basically helping the areas of bottoming cycle for some power industries. In our ’14-’15 Budget Plan, we are looking at doing more work on the Combined Heat and Power, particularly on the Micro scale system, and other for small intermediate CHP. When I say “small system,” it’s slightly different from what you heard 20 megawatt, and we’re looking at less than 100 kilowatt system for small scale systems.

We’re also going to support some breakthrough technologies out there that could potentially, again, help develop for the combined heat and power. I mentioned one of the topic areas included in our natural gas budget which is on the cost-effective natural gas power generation with advanced carbon dioxide just to mention that, although the focus on working on a larger power plant for opportunity for carbon capture, I think there’s an opportunity for synergy with combined heat and power and other emerging technologies along that area. With that, I would like to thank you for this opportunity.

MR. HARVILLE: Great. Thank you, Rizaldo. Our final speaker for now until we get into the broader discussion is Sidney Davies. Sidney is the Assistant General Counsel at the ISO. She has been an energy lawyer for almost 20 years and she began her energy career right here at the Energy Commission. Sidney, thank you.

MS. DAVIES: Thank you very much. You know, before I get into a little bit of talking to you about what the ISO has done to remove some barriers for CHP participation in the ISO markets, I just wanted to share some things I looked up in advance of coming here today because I believe when I was a Staff Counsel here at the Energy Commission, California *was* number one at energy efficiency in the United States. According to the American Council for Energy Efficiency, that honor goes to Massachusetts now three years in the running -- personal disclosure, I am from Massachusetts. California still is in the top ten states, but all the other states are much colder states and have a much higher heating load. How can that be? How did this happen?

I also read recently that Boston and Cambridge are repowering an in-city power plant, adding 30 miles of pipe to capture heat for heating and cooling for 14 high tower residential buildings, for the biotech industry, and for hospitals. It doesn’t seem like that’s even possible in California given the desire to get rid of city located power plants, get the power plants out of the locations where people live, and to build all that transmission.

So that’s actually called District Energy and I believe Thomas Edison invented that. So I think that we have a challenge to go back and reuse some of these ideas to become an energy efficiency state. So if I had created a Powerpoint, I would have called it “CHP: What’s not to Love?” And I think all the speakers have already addressed economic efficiency, and then energy efficiency, my understanding is that the best technology, natural gas-fired power plant, can reach about 60 percent energy capture, but CHP can reach 80 percent energy capture. From an electricity perspective and from a manufacturing perspective, there really should be a win-win here, but I certainly have seen a lot of resistance to seeing the benefits of CHP in my work with the utilities, and the California ISO's efforts to make the ISO's market rules more friendly to CHP. Of course, the GHG benefit goes hand in hand with these energy efficiency benefits.

I did want to, from the ISO grid perspective, there's obviously the local capacity benefit for CHP power plants located in load centers, they have to be located in load centers to have a local reliability benefit. And then ideally, there's capacity that could be available to participate in the CAISO markets, and this is where the ISO has tried to recognize that CHP resources are not primarily in the electricity business for a number of years since CAISO inception in 1998, existing CHP resources were grandfathered, they were exempt from participating in the ISO markets, but they did enjoy what we call a regulatory must-take status, that meant that they had a higher scheduling priority in our markets, and other resources would be curtailed ahead of these co-generation CHP resources.

The ISO advocated for quite some time to try to limit that grandfather status based on the definition in the ISO tariff, however, efforts at FERC met with some resistance because of the state authority over CHP resources, and so several years ago, 2007, the ISO went to the CPUC to require CHP resources to participate in the CAISO markets. And that policy initiative, the CPUC agreed, the QF Global Settlement came out of that. But what the ISO then tried to do was to modify the ISO tariff to continue to recognize the capacity dedicated to the host industrial process as deserving of a higher scheduling priority. So the ISO would recognize there's a business being conducted here, we don't want to interfere with your business, with a capacity that's not dedicated to the host industrial process, would then be in the ISO market without any special high priority, would compete like other resources. What does this do? It really gives you the opportunity for CHP resources to provide ancillary services, additional flexible capacity to actually integrate renewables. So we have just win-win-win right down the line.

It is sad that we have not seen more CHP resources built in California. There is one really excellent story that I do want to share, I don’t know if anyone here is from Occidental or Evie Kahl is coming here at some point, but I did want to share the story of Elk Hills. Elk Hills was built as a large combined cycle resource, it already was sort of cool because it took excess gas from the oil field and burned that. It also has a pipeline that is served by gas. When the ISO had started its stakeholder process to change its market rules, it decided to become a QF, and it did so when it started producing heat, thermal energy for the advanced oil field recovery. And, I mean, that’s fantastic. And then more recently it was Occidental coming to the ISO saying, well, we have a little trouble participating as a net resource because one of the existing tariffs allows the QFs or the CHP resources to be treated as net, your onsite load is netted off, so if you’re a 500 megawatt resource and have 100 megawatts of onsite requirements, we will model you as a 400 megawatt resource. For a large facility like Elk Hills, that left capacity on the table. We had difficulty modeling it as a net resource, so we proceeded to offer a variation of the CHP Participating Generator Agreement where they would provide us the gross telemetry information so we could model it as a gross resource, and therefore use it more efficiently in the ISO markets.

Through all these years of developing these new rules and these variations on how a CHP resource can participate in our market, we have met with really incredible resistance from the California utilities, one utility in particular, and it really required the leadership of the Energy Commission to help us, to help the ISO move through the stakeholder process, to a point where we could take it to our Board and take it to the Commission. That resistance doesn’t really make sense to me since there’s a potential win-win if you consider the full picture of benefits that the CHP resources can provide, and that’s simply not happening in the State of California and none of us can really do it alone.

From the State policy perspective, I think of CHP as energy efficiency, and yet it doesn’t seem to be considered energy efficiency in the loading order. I think CHP should be considered as energy efficiency in the loading order; it still is a preferred resource, but it doesn’t seem to have the priority of other energy efficiency resources.

A challenge for CHP resources could potentially be to be able to consume electricity in over-gen situations. One of the conflicts we have to resolve between renewables and CHP which needs to continuously generate heat for their host industrial process is what happens when we have over-gen, and this is a concern as more and more of our renewables come on line. It’s fantastic to have gas-fired resources to balance those renewables when you have an over-gen situation. One of the issues we face is from a policy perspective: which resource should be curtailed? And first of all, if you curtail a CHP resource, you’re interfering with the business and it seemed like utilities cared more about wind not being curtailed and businesses not being curtailed and, again, what is the full picture of all the benefits at play in California?

But can CHP resources utilize electricity in over-gen situations? I don’t think there’s existing technology available to do that, but there’s an opportunity there. We sometimes have negative pricing and the potential opportunity to pay to consume electricity, and that is a potential benefit.

One of the ISO market rules that also tries to see in the future and to allow greater flexibility is we didn’t tie the definition of a CHP resource to any energy efficiency standard because we anticipated that the ideal facility would be like an Elk Hill facility which would have a lot of capacity available to participate in the market, but if it starts participating in the market, its overall efficiency could look less pretty on paper; but if you look at it from a system standpoint, the efficiency still could be fantastic if it displaced a gas-fired resource that was just a gas-fired resource and not providing any thermal energy to any industry or host industrial process. So you could imagine a world where there are not gas-fired only resources, that all of these gas-fired facilities are located in places where the heat, the thermal energy can be used for heating or cooling, or other purposes. And then if you look at energy efficiency across the state, then you can see the benefits and the potential for CHP to meet numerous policy goals, as well as helping the ISO manage the grid.

MR. HARVILLE: Great. Thank you, Sidney. All right, at this point I would like to open it up and ask the panel as a group if they feel like, I mean, we've heard a lot of different values and benefits here, if anyone feels like there's -- I say a "large category of benefits" or something that hasn't been mentioned, has maybe been missed.

MR. ALCANTAR: I do want to -- Michael Alcantar for CAC -- I do want to stress one thing that is bubbling around the table, but hasn't been maybe said as clearly as we need to. Size matters and CHP, it is several sets of discrete operations and projects. It's terrific to look at a small highly efficient application in a particular environment CEC is doing, but if you were to say how does that fit into a refinery in the load center in Southern California, it has very little application, it doesn't fit, it doesn't work the same way. So as we start talking about the discrete projects and products that we have, I think we need to look at them also as discrete benefits. I think we mentioned this earlier, but I just want to make sure it’s reiterated in terms of how we’re examining the issues going forward.

MS. VAUGHAN: Beth Vaughan with the California Cogeneration Council. And maybe the other side of that too, Michael, is absolutely size matters, but I think on the other end of that is the Elk Hills example, too, where I think Sidney told a really interesting story about the potential. And I have to say myself, when I saw the advice letter filed on Elk Hills, I was extremely interested because it is a new and a different way to approach procurement of CHP under the settlement; however, that’s also very unique because that’s 565 megawatts and 200 megawatts of that are going to be identified as CHP. So I think what that tells us is there’s a whole spectrum of things going on, and I guess one point I want to make, and the person we’re missing up here actually is Dave Mehl from the ARB, I thought you got away with the presentation with no questions, but I think there have been a lot of papers, a lot of documentation on the benefits of CHP, certainly the reason why we have this panel in the morning was we wanted to talk about the value and benefits besides greenhouse gas emissions reductions, which we’re going to focus a lot on this afternoon. And I think you’ve heard around the table here about the economic drivers, about the efficiency and environmental benefits, the resiliency and reliability, and certainly for CCC, CAC, PUC, we’ve got Tom presenting on some of those benefits that we think should be and could be quantified, so that’s also a lead-in and I guess I’m sort of saying to Dave what I would love to see, I mean, I’m very encouraged to hear that ARB is going to lead this assessment and solutions and actually implement solutions because I think, for example, two years ago the Energy Commission produced a great staff report that did a wonderful job coming out of a CHP workshop like this, that identified benefits, identified barriers, had a lot of recommendations, but what we really need is action now. And so I’m hoping -- and this is my bit for Dave -- is I heard you talk about from your perspective, and I completely understand, from the Air Resources perspective you’re interested in reducing energy costs, reducing GHG emissions and criteria pollutants, you're looking at what is the most beneficial technology, and you also said that you like certain applications, and I'm really hoping that my members' applications are some of the applications you like, like the paper manufacturers, or those that do enhanced oil recovery, or perhaps the universities and educational institutions that rely upon Combined Heat and Power. So I guess my message to you, taking this opportunity here, is hopefully you can expand and broaden your scope as the lead agency beyond just greenhouse gas emissions reductions and start to maybe incorporate some of these ideas that we've heard around the table this morning, and particularly moving towards quantifying those.

MR. HARVILLE: Great. Thank you. While we're on the topic, I would just like to ask the panel as a group, what do you feel are the most important next steps that the State's energy agencies should be taking?

MR. UHLER: If you're not going to let anybody else step into that –

MR. ALCANTAR: Let's start with where we

are today and several years ago, I sat in this room actually and we were talking about the benefits to be derived from a thoughtfully provocative, really intelligently designed settlement that's failing miserably, going forward. And that was the ability to say about the CHP settlement was that, and we coined this line, that it was a pier, not a bridge. And it would take us so far, but it would stop and we needed to take some steps going forward, and that's where I think we are today, if not where we've been for a while. There are some steps that are necessary going forward.

So where are we? We're going to hear from the CPUC today about where they are in the LTPP process, where the procurement steps have happened so far to date with respect to the CHP settlement, and as much as we would like to call that a success, and there have been some, they're isolated. We are leaving some important existing projects that are efficient, that are essential service portions of our state's operation off the list of being procured, I'd like to give reasons why that's occurring, but it is a mystery to be able to explain that, except I think Sidney did as good a job as anybody can about running into some problems that we are facing from the procurement agents, essentially, who are responsible. And when we put utilities in as procurement agents for CHP, we need to learn from our experience. I can certainly understand a business model if I were an electric utility and concerned about my future and keeping certain high load factor customers on my system, and not liking competition from other suppliers; there are some good reasons why you, from a business model standpoint, wouldn’t be supporting this particular industry, but it’s gone too far and we need to do some things about solving that. One of the lines, and I really need to credit Beth with this, but it’s an insight that I think needs to be shared about what a settlement is and what a CHP settlement was, it’s not public policy, it’s not a substitute for public policy. It’s an effort by a group of stakeholders to get out of some headaches that they can’t otherwise resolve except through give and take in a settlement process, but it does not promote public policy in the sense that it answers the questions that we are all now facing. So in some respects, it’s the old joke line from Bill Cosby, it's like Novocain, you can apply it, but all it does is postpone the pain. And I think that we're at that point where the Novocain is wearing off, we're seeing the results of that non-public policy settlement coming to fruition, and we've got some things that weren't answered, haven't been resolved, and need to be resolved now. We have an opportunity to do that, that's what the LTPP proceeding provides for us, and Dave Mehl's work certainly needs to feed into that hopefully sooner than later, Dave. 2016 is after 2015 and 2015 is when we're going to have hearings, we hope, in the LTPP about this very subject, what do we do in the second program period under the settlement?

MR. HARVILLE: Thanks, Mike. So I definitely hear what you're saying about concerns over maybe the utilities incentives in the procurement process, and also the CHP settlement not being a substitute for policy, and so I'm curious specifically which kind of policy you would like to see in place of the CHP settlement? I mean, what policy are we not addressing by having this settlement in place?

MR. ALCANTAR: The stated goals of the settlement were to try and assure that certain existing efficiency resources -- we were trying to make sure that we had identified what efficiency meant and to define it -- would have a going forward opportunity to participate in a market that was segregated to those similar types of facilities. And the fact that our firm, for example, represents Occi, so we're very proud of what that project represents, but taking a step back, if you were other types of facilities in that marketplace, you're not all that happy about that creativity because what it did was it distorted the type of project that you thought you were engaging the settlement for, right? You were a base load facility that couldn't otherwise compete in all source bid resource plans, and you needed to find another way to be recognized and procured. Those procurements are now substantially at risk, so there are a number of megawatts, by our count there is about round figures of 1,200 megawatts of efficient CHP that are chasing about a remaining less than 400 megawatts of available procurement under the CHP settlement. So what that means is there's a good number of existing CHP that will not be contracted for, is going to move into an ISO market that virtually everybody acknowledges and understands will not sustain those operations, and those facilities will likely figure out exit strategies. That’s not what we were trying to do.

Similarly, we’ve created situations where the incentives that we’ve sent out, or that have resulted from the settlement, have been for people to install boilers, suddenly become flexible hosts, you know, if you will, “I can take power from my CHP if I need to, but I’ve got enough boiler capacity installed that I can run those.” If you’re thinking about that from a CARB standpoint, or a public policy standpoint, the last thing we were trying to do was incent boiler installation. It was to retain CHP and to promote more of it so you would gain those efficiencies and eliminate the emissions that went with it. So those are the policies that we were trying to attain, we haven’t attained them as implementation has gone forward, at least fully.

MR. HARVILLE: Tom?

MR. BEACH: Yeah, I'd like to kind of follow-up what Michael just said from a perspective of new CHP, I mean, I think that's the other thing that we haven't seen, we've seen very little new CHP in the state. And I think that, you know, obviously new CHP, there's a capital cost hurdle that you have to get over, I mean, a new project has to be able to pay the cost of building it and also needs to have a revenue stream that is assured for a long enough period to pay off the money that you're going to borrow to build it. And you know, certainly I think it's pretty clear that a 12-year contract is provided in the QF settlement for new CHP, it's just not long enough to allow new projects to pay off their loans, and it's such a short period of time that it means you have to ask for more money in your capacity price in order to pay off your project over that short a period of time. So, I mean, that's certainly one area for new CHP.

Then the benefits that I went into in my presentation are all benefits that have been talked about for many years, but there's never been any action to actually develop policies that these benefits need to be recognized in the procurement process, and in the evaluation of these resources when they bid into a utility RFO. And that certainly is something squarely, I would think, under the purview of the CPUC to take a look at these kinds of additional benefits and to make sure to incorporate them into the procurement process.

I would observe that a number of these benefits also apply to other kinds of distributed generation, renewable distributed generation -- avoided transmission costs, reduced GHG emissions, price mitigation benefits, enhanced reliability and resiliency, those all come from other types of distributed generation, as well as from CHP. So there's a need for the CPUC to take a look at these kinds of benefits in a broader way than it has done in the past and to require them to be considered in the procurement process.

MR. ALCANTAR: I might jump in and piggyback on Tom, we're doing it back and forth, but just a rule of thumb, for a company investment, choice of capital investment in a CHP project versus boilers is about a 5:1 ratio, rule of thumb. So somebody who is making that form of commitment, and this is what Dorothy was pointing out, if you're making that form of commitment you're likely to be serious about what you're committing to and staying with. When you're a multi-national or multi-state, even, operation you start making choices based upon that investment cost: why here? Why not somewhere else where things are better and cheaper? So those are the things we're seeing. And once somebody make that choice to make a boiler investment, you're done for a very long period of time, if not permanently, from a CHP investment. So there's this race, if you will, the switch is on or off in terms of CHP going forward, based upon those motivations right now. So if you're looking at a 12-year contract competing against a utility asset or something that's going to amortize itself over 30 years, you're just -- you can't compete, you're not in the same ballpark.

MR. DAVIDSON: I'll just, and some of these comments may be applied to the larger systems, selling back as well, but from the vantage point of the small CHP industry, the people that have got to put up the money for CHP plants, I think see a lot of uncertainty in

California about which way, you know, how certain policies are going to be implemented, and they also see a trend in the electric rate design, putting more and more of the costs into fixed costs that are either not possible to avoid when you put in CHP, or more difficult to avoid when you put in CHP. And so to me, the state needs to work hard and, Dave, I'm looking forward to CARB's efforts here, but to eliminate some of the uncertainty in the face of a lot of the end users and decision makers, and to develop some consistent policies and regulations that aren't so contradictory, as many of them are today.

I've got just a comment and a question for Sidney. I was very happy to hear you say CHP is energy efficiency, I think a lot of people in this room would agree with that, and we'd love to see CHP get similar treatment as energy efficiency. But the question I have for you is you talked about the capacity value of CHP, I think you were mostly talking about people that are providing a power back into the wholesale market, but the question is, I think, that people that have onsite CHP also provide capacity value. CHP as a class has an availability factor above

90 percent, probably closer to 95 percent, maybe even higher. I mean, shouldn't that class of CHP be entitled to some form of capacity credit? I'm just curious what your thoughts are.

MS. DAVIES: Well, I certainly agree that there's a capacity value for local reliability for -- even if you're not exporting, if you're just on, supplying your onsite load. The CAISO, you know, performs its annual local reliability studies, it is starting to look at its assumptions for which resources, or how much capacity is needed in a local area, and the assumptions are more evolving to recognize that not to assume that CHP is just on, and so we just see what incremental resources that we need, but to put that in the funnel as well. Now, if you're not exporting at all, I think it's going to be hard for that value to be seen. If you're a zero exporting resource, it's a little hard for the ISO to value that. But if you have some export capability, and are participating in the CAISO markets at some level, I think there will be some evolution at the ISO that will help the transparency for that, that this capacity will be seen as needed for local reliability in a more clear way.

MR. DAVIDSON: Yeah, I would think that there are some mechanisms you could put in place to have people that want to benefit from the capacity value to be part of some reporting, some central reporting system so you can track how much of it is on line and maybe even have some kind of a dispatch function to say if you're planning any maintenance that can be put off for a month; for example, if it's in August, please put it off. I would think there's a lot that can happen to make a better use and benefit of the onsite generators.

MS. DAVIES: There would need to be some kind of relationship between the entity and the ISO. If you can contemplate that, then there can be a dialogue, otherwise there's really no visibility.

MR. DAVIDSON: There would have to be visibility, but maybe, I don't know, maybe the ISO doesn't have the appetite to deal with many hundreds of CHP users, and maybe there's an aggregator or central --

MS. DAVIES: I think what we are trying to work with the utilities who have a lot of small distributed resources, a lot of them are wind and solar, they're QFs, but we haven't seen the distributed CHP so much yet, but we're trying to encourage aggregation and participation of those smaller resources. I would think the same could apply to the CHP. If they're willing to participate in an aggregation, the tariff threshold is if you're less than one megawatt, you don't have to participate in the CAISO markets, you have to be at least 500 KW or participate in aggregation if you're smaller than that, so there's sort of a threshold for us. We have lowered that threshold, so I guess if you get smaller resources, but aggregation becomes essential because of our systems, we reach the finiteness of our system to model all these small resources.

MR. DAVIDSON: Thank you.

MR. HARVILLE: Actually at this point, I'm sorry, I know there's a lot more to discuss, but I do need to open it up for public comment. I'll start with the audience and then I'll move to the online audience. Do we have any comments from the audience, questions? Yes, sir, in the back there?

MR. UHLER: I’m wondering about if the CAISO has done like a resource leveling chart like the duck chart showing how CHP would affect the duck chart. And also, do you have a dissection of the head of the duck and what those loads are?

MS. DAVIES: I’ll have to take your suggestion back to Karen Edson who is the mother of the duck chart and let her know that the duck chart has gone viral. But that’s an interesting question. We haven’t.

MR. UHLER: Well, I have taken all of the resource watch data and done charts for every day through 2011 through now, and I find other constellations, I find hummingbirds in the chart, I find other types of shapes and such, and in looking at that, I try to find the greenest time of the day to use electricity and such, but then I also kind of see situations where if you have somebody who has intermittent CHP, you could end up with a lot of trouble, or if you have somebody who runs their CHP in a sliding cycle, not a top or a bottom, decides to dump their excess electricity into their heat load, they would be invisible to you, but totally removing that load, but maybe one day suddenly needing all of your electrical load back. Just things like that because I find like the whole notion of the duck chart, it's like we've gotten this far, where is it in the fossil record? Maybe 2011 that it starts showing up? And I'm thinking we go forward on all this solar and nobody did a duck chart back in 1962 or something like that?

MS. DAVIES: Well, I will take that back, I think it's an interesting thought. I think as CHP is capable of being a much more flexible and much less intermittent, much more predictable than the intermittence, and to the extent it has capacity on top of that, I mean, upward ramping and downward ramping, they could provide a value that the truly intermittence can't right now.

MR. UHLER: Will the CHP be able to help in the ramping situations? Or can you eliminate the ramping situations like doing away with all the all-electric home situations, because there's already -- you're only 40 percent efficient on your heating in those right off the bat, and that would parlay into -- my main thing is micro-CHP -- could micro-CHP be applied against all of these all-electric homes to show the total very much benefit of, instead of using 40 percent heating efficiencies they suddenly rise to 95 and introduce people to all kinds of other efficiencies. And then with those efficiencies, is it likely that those to CHP are already going to be pretty highly efficient and you’re going to have to transport the electricity out of their zones because those folks actually won’t use that much electricity and you’ll have to be moving it to someplace else, putting more strain on a system that maybe has primary and secondary transformer situations that you can’t move that electricity very easy. Taking the example of PV on the rooftop, I see stuff where people are talking about curtailing that and wanting smart inverters and things so you can shut that down, harmonic problems because it appeared that they assume that these inverters would be voltage support devices. Are all of those things going to be applied here? I understand there is some study on harmonics. Are you going to make sure all your CHP systems won’t have synchronizing problems, start swinging against some of the other resources? Is that kind of thing being done?

MS. DAVIES: It sounds like a good thing for the Energy Commission to look at.

MR. HARVILLE: I think that synchronizing is part of the interconnection process and the utilities definitely want to ensure that synchronous generators are synchronous.

MR. UHLER: Yeah, yeah, but apparently that kind of study wasn't done way back when local utility took one of their Folsom sites and they just assumed that the inverters would be no problem, and they would support voltage. But now they're saying they're not really good for that, so my point is we've come a long way, but somebody didn't do these studies. Duck chart, is it 2011 maybe, and the fossil record? It seems way late into the process. We should do that on CHP. I totally like CHP --

MS. DAVIES: Yeah, I think it's a fair point.

MR. UHLER: -- I would like to see it succeed, but I don't want it getting pushed out because somebody says, "I now have to curtail my power and sell it in another market, or pay somebody else to take it." So thank you.

MR. HARVILLE: Thank you. Do we have any

other here? Sir?

MR. BLOOM: Hi, my name is Jerry Bloom and I’m counsel to the California Cogeneration Council. I’ve been working on CHP in California since 1980 and if we look back in the ‘80s, we had a certain big investor-owned utility who bragged they were QF bashers, and we had another utility who had a campaign out with a guy on a heart monitor, and if let CHP into the portfolio, there was going to be failure of reliability and stability in the system, and the guy on the heart monitor dies because the power fails. This really happened in the ‘80s. And my point is, we’ve been at this war, if you were a battle, for over 35 years now, and the reality of the situation is there’s just enormous -- and I sit here frustrated, actually, you see these goals of 6,500 megawatts, and 4,000 megawatts, and there’s such a tremendous disconnect between the reality of what’s really going on and what’s really being procured. Michael Alcantar said the settlement is failing because what was supposed to happen were efficient, base load co-gen needed a home so we could do what Dorothy talked about, where you have manufacturing and people can make investment, and we’re getting anything but that out of this settlement. When we look at where we’re going, we need, to answer your question: what do we need to change? We need a couple things, 1) we need some incentives that need to be put in place for the IOUs so that we can stop the battle. And it’s the fox in the chicken coop, Tom made this point, if the person who is procuring CHP is against CHP and has been against it for 35 years, duh, what happened with the settlement? We didn’t get a whole lot of CHP out of that settlement is what was really happening. So we need a different set of incentives for the utilities so that we don’t have that problem. The second thing, frankly, which is the elephant in the room, and it’s not just with CHP, is what is the future of the utilities, what the modern grid is going to look like, and what’s the utility’s role and what is the makeup? Because people talked about incentives here against bypass, and the incentives are to keep customers and the customer base. So we really have to have a real discussion about what’s the modern grid going to look like, and what are we going to do with utilities. Because if you want the status quo and you want to keep it the way it is, and put the utilities in charge of procurement, who don't want CHP, and look at the results we're going to get. So we have to look at utilities, we have to look at incentives utilities, and this is not to bash the utilities, it's we have to take care of the utilities, they are absolutely critical, the function they provide is critical, it's not going away, but we've got to modernize it and we have to figure out where it's going to go if we're going to solve the CHP program and get through this disconnect. And the third thing I'd like to put on the table is in terms of your question, what needs to be done, we need real policies and that may mean we even need laws. The way the RPS got pushed through was there was the Renewable Portfolio Standard, and there wasn't an option here, and we have to stop kidding ourselves that we're going to set up these programs. We spent 17 months negotiating the settlement and where have we gotten? We haven't gotten close to certainly what we thought we were keeping in terms of the existing, but we haven't gotten anywhere in terms of new generation and new CHP, as Tom Beach shared, we don't have anything being developed in the state, so let's stop kidding ourselves we're going to reach 4,000 megawatts when we don't have any programs in place to get us anywhere. And if we're really going to mean this, and we're really going to go after it, we don't want to be tenth in the states or worse, as Sidney pointed out in terms of us dropping, we need real policies and we need some real laws. We need some stuff that says we're going to do it, and then programs and incentives that make it happen. But in that process, we have to figure out the utilities and take care of that, or we're never going to get through these hurdles because we're going to get mired in these proceedings, whether they're at the California Energy Commission, whether they're at the PUC, whether they're before the ISO, and the opposition that Sidney talked about, that's what's preventing us from getting anywhere. So we have to take care of the elephant in the room if we really want to make sense here and we want to progress. Thank you.

MR. HARVILLE: Thank you, Jerry. Do I have any comments -- oh, thank you.

MR. LARREA: Thank you. John Larrea with

the California League of Food Processors, and I just couldn't pass that up as a perfect segue. You know, one of the things we're dealing with here is the fact that we seem to choose our technologies associated with this, kind of like the high school popularity contest, whoever is the cutest and the coolest is the one who is going to receive the most attention. And so one of the things we're trying to do out here is there's a bill out right now called AB 1763 being carried by Assemblyman Perea, and what it wants to do is set up an overall energy policy. And I think this might benefit the effort being made here to be able to compare CHP against the other technologies out there, instead of the current way we have, which Mike kind of pointed out, it's not that it's not public, but it's so esoteric in terms of the people being able to deal with it, the public doesn't see the benefits that may be had through CHP. So I would put it to this panel maybe to kind of take a look at that bill and see if maybe your particular groups might be able to support that and let the Governor know that, too. Thank you.

MR. HARVILLE: Thank you. Sir?

MR. HOFFMAN: Hi. I'm Bob Hoffman with Occi, and thank you for this workshop, it's been really enlightening, and especially thank you, Sidney, for the kind words about Elk Hills Power and others' kind words, as well.

Just for a little bit of a correction on Elk Hills Power, it's a 550 megawatt co-generation facility. When I grew up, it was called co-generation, not CHP, but it's also CHP, and it's not 200 megawatts of CHP, it's 550 megawatts of CHP, of which 200 is under contract. But it is a useful, effective useful industry use of energy in many respects.

But I wanted to pick up on a few things, I think, on your point on the capacity value because I look at Elk Hills Power, we're not only the largest wellhead natural gas-fired power plant probably in the west, we're probably the largest DG project, Distributed Generation, distributed energy. And to your point, I think there is a value in capacity that we're providing behind the grid, and we are exporting to the grid, so it's seen by the ISO; but even if it wasn't, I believe that there's a reduction in load, and in that load pocket, to the extent it enhances local reliability, we're not in a local reliability critical area up near Bakersfield, but if it was let's say in Los Angeles, or in the LA Harbor area, like some co-gens are, I believe that that generation does in fact help the ISO, or help the grid and help the state, and because the ISO doesn't see it necessarily, it's hard to recognize or model that. So I think looking forward for either small aggregated distributed generation, or distributed energy resources, or some of the larger ones in the state, that capacity value needs to be somehow acknowledged, that attribute. Thanks.

MR. HARVILLE: Thank you. Do we have any questions from the online? And any more questions from the audience? Thank you.

MR. MARIHART: Yes, good morning. My name is Tom Marihart. I work with Western Energy Systems in General Electric. We deal with a lot of engineering companies, end users, and developers that are actually on the front lines trying to deploy Combined Heat and Power in a lot of places from, you know, the oil and gas industry to the food processing industry, to a sizeable amount of renewable projects, all making maximum efficient use of Combined Heat and Power. And just a couple comments. I've had more than a few developers run into problems with just simply how to cope with AB 32 and CHP. We've been awaiting some sort of a ruling or clarification of how CHP would be treated under that regime, and some of these plants are very efficient. We're talking, you know, low heating value of 75, 85, and higher percentages of total thermal efficiency. And in some cases they would be lower than the actual utility grids to which they're connected -- not the state average which is around 1,100 to 1,200 pounds of CO_2 per megawatt hour, but a third of that in some cases. And some of these customers have actually held off doing projects and doing CHP because they don't know how they're going to be treated under AB 32. Maybe one possible way to do that is to set a threshold above which, if you have a basic efficiency, that you should be exempt from AB 32 for the gas that you're using to drive CHP, especially in some of these critical areas of food processing, energy production, and other areas that, when the grid goes down, maybe having that resource there would be able to provide off-grid support so they don't lose money and have higher costs of doing business in California, you know, something Dorothy touched on because we really don't have exactly people beating down our door to do business in California. And CHP is one of the few technologies out there where you have the ability to use available natural gas to produce energy at half the cost of the grid in a lot of cases.

And something else that's been in the way of some of these projects is, you know, half the projects we work on are renewable projects, the other half are fossil fuels. And all the resources in the self-gen incentive program pretty much are gone for biogas, they've been pretty much cannibalized by other technologies that are less efficient like fuel cells and batteries. And most of these things can't get above 70 percent efficiency, in fact, many of them raise grid emissions and grid costs. And for all of those funds to immediately go to those other more, I'd say, popular technologies, harking back to the other gentleman's comment on like the high school popularity contest, it doesn't make us more competitive, it makes us less competitive, it raises the cost of our energy in the state. So we should incentivize efficiency and lower cost to deploy technologies to help drive down the costs of doing business and powering business in the state. So I would implore you to have more SGIP oversight, some of the renewable fuel use reports from past years like 2013 have yet to even be published, so we don't even know who has used what and how effectively, and many of these companies are still heavily over-subscribed in the SGIP program, in fact, they've pretty much taken a good chunk of the funds, leaving very little if anything for true renewable biogas development to electricity, for example.

I'd also point out that some of these other technologies have favorable treatment on interconnections. What if above a certain percentage of efficiency were able to actually net meter CHP? That would be a help. If you're above a certain base load of efficiency above that of most common fuel cells today, shouldn't any technology suitably efficient be able to do that? That would help support the grid and roll out quicker deployment of these technologies.

And there's also the old gripe of standby fees and departing load fees. You know, most one megawatt facilities are at about a one to two cent kilowatt hour disadvantage over some of the net metered equipment because they're exempt from those fees. CHP 10-cent power is at about a 20 percent disadvantage, and they can actually produce dispatchable base load, island capable resources to support critical infrastructure, whereas other net metered things typically can't, they have to go down when the grid goes down. So, I mean, we're really hamstringing one of the lowest cost, most efficient resources that we have, that we could deploy in the state. And that's all I have to say for the time being, I'd just like to see, again, some AB 32 clarity for CHP, I'd like to see more SGIP oversight for the funds, and I'd like to see some simplification for some of the interconnect standards and fees that CHP is seeing today. That will help get you more quicker if you really want it. Thank you.

MR. HARVILLE: Thank you. Do we have any other comments? All right, then at this point this will conclude this panel. There's been so much good discussion that we need to make up a little bit of time, so I’m going to take just a five-minute break now, please, stretch your legs, and like I mentioned there are restrooms straight across the hallway here. We will start the second panel at 11:20 by this clock over here, and if I could just have all the panelists for the second panel take your seats before the break is over. Thank you.

(Recess.)

(Reconvene.)

MR. HARVILLE: All right, our second panel of the day is going to focus on small CHP and by “small” for these purposes we’re thinking up to 20 megawatts. And I know we’ve had a lot of discussion already on some of the large ones, specifically Elk Hills, which is a very large co-generation facility. I’ve already introduced him, but you’re moderator for this panel is going to be Keith Davidson over here on the side here, and he will introduce the other panel members as they come, but we’re going to start off with a presentation from you, Keith?

MR. DAVIDSON: Yeah, I just want to make a few introductory remarks and, you know, this is small CHP. I think different people here might define small CHP differently, but for the purposes of this workshop, it’s less than 20 megawatts. And can I get the next slide, please?

And this is our panel and I think everybody is here except the person that is last on the panel list, Casey Houweling, he should be on his way right now from the airport to here, so we put him last so hopefully we’ll be able to hear his story, which I think is pretty fascinating. And what I’ll do is introduce each panelist right before they give some remarks.

So if I could have the next slide, please, I just want to put a couple things in perspective. The California Energy Commission sponsored a CHP Policy Analysis and Market Assessment a couple years ago, it was published in 2012, I think, on the CHP market in California, and in the size range that we’re going to be interested on this panel, less than 20 megawatts, they identified a market potential of customers and new growth activity that was anticipated over the next 15-18 year period to yield the opportunity for an additional 11,000 megawatts of new Combined Heat and Power in market applications that had the right kind of market characteristics or application characteristics to promote an efficient CHP system.

They also looked at various policy scenarios and what a projected implementation would be over that period of time, several scenarios, but the most aggressive scenario for policy and market support for CHP said that you could have an additional 3,500 megawatts of CHP -- again, this is in a less than 20 megawatt size range -- in place by the year 2030. But what we want to do in this workshop is kind of share some CHP experiences and we've got a couple case studies and other people on the panel that have some real world experience with selling, implementing and operating CHP, and we want to try and better understand the reasons for the current lackluster CHP market activity, and then identify some recommendations that put small CHP on a robust implementation trajectory. Next slide, please.

What I thought I would do was just -- I picked a couple of topics that I, I don't know, I may have missed some of the panelists, but I picked a couple of topics that I don't think were necessarily being addressed, but that I think are important. And one of them I want to just touch on is AB 32 that Tom from Western talked about, and the cap-and-trade impacts. And what you see there on the right is the blue bar represents the marginal resource for 2020 that the CPUC has identified, is what CHP would displace, base load resource would displace in the year 2020, and the two bars on the right, the green bars, one of them is a turbine, one of them is an engine, are kind of the net CHP emissions, and so you subtract out, you take the total emissions and you subtract out the emissions you otherwise would have had with your gas boiler that you're displacing, and you'd come out with a net greenhouse gas footprint. And so you can see that in terms of the value to the state, the difference between the blue bar with the red transmission and distribution piece on top minus the tops of the green bars give you what the greenhouse gas value is for Combined Heat and Power from a greenhouse gas emission point of view.

But then I want to compare that against what happens with the economics because in 2015 it doesn't matter anymore if you're in cap-and-trade because the cost of CO_2 is going to be passed along in the price of gas to customers that aren't in cap-and-trade, and so this affects most people with the possible exception of the energy intensive trade exposed industries that do get some free allowances for a certain period of time. But for all those people that are into the full brunt of cap-and-trade and all those smaller customers that are going to see the cost of CO_2 in their price of gas, that price is also going to be passed along to the electric retail price to the consumers, but not in the same manner as the avoided emissions is calculated. It really gets passed along in terms of a blend of fossil fuel generation versus non-fossil fuel generation. And you can't see that graphic off to the left very well, but there's a 2012 fuel mix for electricity that is in kind of the second column there for 2012, that's a CEC report, 43 percent natural gas, a little over seven percent coal, 15 percent eligible renewables, and then about nine percent large hydro, and then there's some unspecified resources that get into the mix, as well. And then I kind of tried to guess a little bit as to what it might be like in 2020, I X'd out the coal, and I made the renewables 33 percent. And so what that kind of red pinkish bar represents is what the average greenhouse gas footprint is for the California grid as a whole in 2020. And you can see that, as a whole, that's quite a bit less than what CHP does, which is unfortunately the way the economics are going to show up to users of Combined Heat and Power. Next slide, please.

And so this just kind of looks at one situation, this is what happens if CO_2 gets up to $40.00 a ton, and as Tom mentioned, a lot of people when they're looking at CHP and trying to figure out what is cap-and-trade, what is AB 32 going to do to us, they don't necessarily just look at, "Well, CO_2 is selling for $15.00 a metric ton," they're saying, "What is my potential exposure?" And I put $40.00 a ton up there as it might not be the ultimate exposure, but it's probably the high end of where people think that it could realistically go. And in the blue part which is above the zero cents a kilowatt hour, it says your value to the state basically as a CO_2 reducer in the state is a little less than five cents, or $.5 a kilowatt hour, or I think it's like $.043, I can't read that.

But in terms of your economic penalty that you're going to see as a result of cap-and-trade, it's like negative, so you add the two together, you get almost close to a one-cent kilowatt hour difference between what it's costing you versus what you should be receiving if the benefits were in line with the economics, which they don't appear to be the way that this is being implemented. So next slide, please.

So that's kind of just a little blurb on cap-and-trade, AB 32. And then the other one I wanted to show was how important rate design can be to CHP, and what I've shown here is Southern California -- Cal Edison, investor-owned utility, and LAWP which is a municipal utility, and I looked at a current economic case for SCE versus LADWP, the same technology with a 1.1 megawatt engine system, and you can see that in LADWP's case there's really nothing in the rates that you can't avoid with CHP, and in SoCal Edison territory there is standby chargers and there's departing load chargers, which you can't really avoid under any circumstances, at least as I understand it. And those two charges together represent about 27 percent of the cost of electricity that otherwise would have been avoidable if you were treating things the same way as LADWP does. So you take a 27 percent hit off the top that there’s no way, nothing you can do to really get at that penalty. And what’s not shown here, all the other kind of demand charges and things which are very very significant, but with reliability and I would advocate that, wherever possible, you put in more than one unit, and maybe even put an N+1 unit to really get at avoiding some of these other demand charges. And I just -- the trend seems to be on rate design, at least in California, is to put more and more cost into the fixed charges and demand charges, and less and less in the energy charges. So that’s kind of a trend.

I would point out that there is a special rate that’s been set up for people that have renewable resources that the three investor-owned utilities offer, that have a lower demand charge and a higher energy charge, so the rate is the same, but you don’t get penalized if you’re down temporarily, and I would submit that in the case of Combined Heat and Power, that really isn't vulnerable to having a whole class of customers go out just because a cloud comes over, that as a class, you know, they might be 90-95 percent available as a class, and would very much benefit by a like rate, similar to what's being offered for the renewable industry. And if I could go to the next, I think that's really it. So you can turn that off. I'm going to go ahead and turn things back over to the panel now.

And our first panelist is Debbie Chance who serves as General Manager of Commercial Regulatory Strategy for Chevron Power and Energy Management, which provides comprehensive commercial engineering and operational support to improve the reliability and efficiency of Chevron Power operations worldwide. Debbie provides guidance on regulatory matters to major capital projects and base business, as well as leads Power Supply Agreement negotiations for Chevron assets. Debbie has extensive experience in the Power and Gas industries, both domestically and internationally, and graduated cum laude from Rice University with a Bachelor's Degree in

Managerial Studies and Economics. Debbie.

MS. CHANCE: Thank you so much for inviting me, Jason, I really like talking about CHP. All right, we've already done the intro twice, so I'll just get right down to it. It's really easy to think of Chevron as big CHP, and actually you would be right, we have many very large CHP plants, but you may not realize that we also have quite a few 20 megawatt and lower plants, and we do quite a few small CHP plants, as well, to improve efficiency in our operations. So I will focus the majority of my remarks today on small CHP. Next slide.

The topic was deciding whether to invest in CHP, and the most important question is, does it fit your operations? Can it meet the needs of your business efficiently and economically? For Chevron, the answer is yes. For Chevron, it's all about the heat. We're a very energy intensive business, our interest in CHP is about the "H," not so much about the "P." The "P" makes it more attractive in a state like California with high delivered power prices. We're thermally driven and our business is energy intensive with a huge steam demand. As a large energy user, we always look for ways to increase our efficiency of our operations, and CHP allows us to reduce greenhouse gas, to reduce fuel consumption, and to operate more economically. If we could go to the next one, please?

So I’d like to talk to you about economic and regulatory challenges that CHP faces. Departing Load has got to stop, full stop. I’m both personally and philosophically opposed to paying exit fees. Surely, we could at least agree, if you want to agree to eliminate Departing Load, you could at least agree to limit how many years you have to pay Departing Load on a project basis. We acquired a CHP asset in San Joaquin Valley 13 years ago that was paying Departing Load charges and we are still paying Departing Load charges every month, for 13 years now. Under the current rule, we will continue to pay Departing Load charges into perpetuity. Surely we could agree to some time limit on how long these charges can be applied.

Behind the Meter issues. We have been operating in California for over 100 years. The most likely place for us to make energy efficiency improvements in our operations are actually in our operations, unsurprisingly. But that seems to put our existing contracts at risk. We had a very frustrating experience with the pilot project. We had a patented technology that we wanted to test, we wanted to install this small CHP plant on an existing operation. And initially our existing contract was put at risk. The proposed site had an interconnection for 20 megawatts, but we only exported around eight megawatts. The project was small, it was less than a megawatt, and it qualified for AB 1613, but we would have had to build and pay for an entirely separate interconnection had we decided to go with an AB 1613 contract. Ultimately we were allowed to add the small project to our existing contract by limiting the export capability, but it took us four years to do this. And unfortunately the project didn’t work, I’ll have to tell you that right up front, it was a pilot, it was a test, and it didn’t work. And we’re currently decommissioning this project. But we would have loved to have had that news sooner than later, four years later. Sadly, I think this will stifle innovation here in California. We will look for other places to pilot new ideas.

Before we leave the behind the meter issues, I actually would be remiss if I didn’t mention a positive thing that has happened with us. We had to get a new contract for one of our refineries and actually PG&E was very open, they listened to what we needed, and they allowed a great deal of flexibility for that facility. It was a good outcome and I have to acknowledge that, and I worked with Evelyn on that, and I wish Roy were here, but that was a very good negotiation and we appreciate that.

So leaving behind the meter behind us, I’d like to return to AB 1613. AB 1613 contracts have attractive rates, but they’ve proven difficult to execute. You can’t use an existing interconnection. We have a repowered plant in San Joaquin that qualifies for an AB 1613 contract, and we requested our first AB 1613 contract in January of 2012. We hope that we’re close to execution of this contract. You know, first the certification process itself takes time, the mechanism for greenhouse gas reimbursement is not straightforward. Basically we’ve been working on this agreement for over 30 months and we're hopeful that we will get this done. Next slide, thank you.

So how can the State support the development? Well, let's remove the barriers, eliminate departing load charges, or at least limit how long departing load charges can be charged. The interconnection process is very rigorous, and rightly so, but it's also very rigid. It's hard even when you're already connected to connect. Let's look at just another example. Let's assume you have a site that was studied and an interconnection that was built for 10 megawatts, but in reality you only export four megawatts. It shouldn't be hard to add a three to five megawatt facility behind that meter, but it is. It should be a no brainer to add a pilot project, or a small bottoming cycle plant for efficiency improvements, it's in the scope of the original approved interconnection. In the example I gave earlier, it took us four years to do that.

I'd also ask that you protect our industrial process. We are balancing a very complex steam plant operation, we're not a merchant plant, we're in this for the heat, we can’t be dispatched, we need stability for our operations, so don’t change our existing contract, don’t ask us to ramp up or turn down, except in emergency situations, and I don’t mean economic emergencies -- true emergencies. Again, we’re balancing a complex steam operation.

CHP should be in the toolbox for both the State and the utility, it should be part of your absolute toolkit for greenhouse gas reduction and for energy efficiency: deem CHP energy efficiency measure, deem CHP a compliance mechanism for greenhouse gas reduction, deem the waste heat capture as clean generation. There was a paper that the EPA and Department of Energy put out in August of 2012 called “CHP: Clean Energy Solutions.” And in this paper they state that 23 states recognize CHP in one form or another as part of their Renewable Portfolio Standards, or in their Energy Efficiency Resource Standards, make it simpler to do the right thing. I’ve seen numerous lists that are compiled about barriers to CHP, and I was encouraged to hear Dave talk about moving from an inventory list to an actual to-do list, and we fully support that. Thank you very much.

MR. DAVIDSON: Thank you. And Jason, we'll put questions off and discussion until after all the panelists talk. Thank you, Debbie.

Our next panelist is Steve Acevedo. Steve is the President and CEO of Regatta Solutions, which is Capstone Turbines' Western U.S. distributor covering California, Oregon, Washington, and Hawaii. Steve leads these efforts having 25 years' experience in energy and high technology entrepreneurial management, energy and data center consulting, and infrastructure support. Steve.

MR. ACEVEDO: Good morning. Jason, how long do I have?

MR. HARVILLE: Fifteen minutes.

MR. ACEVEDO: Fifteen, okay. I represent Capstone Turbine on the West Coast, specifically here in California, since we're talking about California issues today. We have represented Capstone for the last five years. We are from a revenue, I guess, success standpoint, we're in the top five distributors worldwide for Capstone, so we have been very successful moving CHP projects in the California arena, despite all the barriers and setbacks that I think you'll hear here today.

When I wake up in the morning, you know, it’s a new day and I like to focus on the positive aspects of doing business, so that’s what I kind of want to share with you, with the 15 minutes that I have, and hopefully we’ll get some questions after this thing.

Who are the markets we serve? Food processors, manufacturers, healthcare, and oil and gas, but not specifically just all oil and gas, we’re doing a lot of -- even with some of our oil and gas clients, we’re doing some CHP applications. We’ve had a significant amount of success in some of the healthcare and hospitality markets, hotels for us are a great venue for CHP where we can actually come into actually heat pool water.

Our technology isn’t the sexy technology, I mean, what we’re selling is a hot water heater that happens to produce electricity, or an air-conditioner that happens to produce electricity. It’s that basic, but it’s that basicness that really talks about a level of efficiency and a level of improving operating expense for our mid-market clients that we serve. So we’re dealing in the mid-markets. Our typical projects average between $2 to $3 million all in, and that's a total product and construction cost. We're seeing higher end with Capstone's product line, we're seeing a lot of higher end entre into megawatt plus projects, which of course is taking the revenue numbers and taking it up.

We typically have, you know, I call it kind of the four challenges of doing a transaction in these mid-market spaces. You know, the first one, of course, is C-level executives that you can actually do something with thermal energy that makes sense on their bottom line. So after we go through that process, the next one is dealing with the actual construction cost. In a lot of the environments that we're selling our product in, you're dealing with a lot of retrofitting, so that becomes costly. So if you want to look at it maybe like a new incentive for CHP, if we can maybe incent for like new construction, new industrial construction, that maybe there are some incentives out there to consider implementing CHP as part of a new construction element because that might reduce the overall cost and acceptance of the technology that we deal with. So dealing with the construction cost in terms of reducing it, we’ve had a number of instances where, you know, we’ve worked with a client that brought in three or four different construction companies, and all of a sudden had that business case taken from, let’s say, a three to four-year payback to, you know, all of a sudden it’s a six or seven-year payback, so those are the economics that kind of basically kill a deal for us.

On average, the kinds of projects that we’re seeing our customers accept typically have between a three to five-year payback, so those are some pretty good economics, particularly for a firm to invest in their existing infrastructure.

Some of the additional issues and considerations for clients are, you know, are they going to stay in the state? So, I mean, if they’re planning on moving, then they’re not going to be investing in the technology. And so that’s a higher level issue from a State economics standpoint that I think needs to be considered.

The next items are the air permitting and interconnect. From an air permitting standpoint, for at least for our technology, we're considered best available control technology for all of the Air Quality Management Districts in the state, so it's not so much a question of are we going to get permitting, the question is when. And these projects get delayed significantly, as much as nine months. So we can go through a sales cycle and actually convince a business to invest in the project, and so that will take maybe four, five, six months, but we can't start the project for another nine months until we get Air permitting. And that's, you know, you talk about inefficiency, that's crazy. And so much happens in the course of a business over nine months that, you know, you could have that decision that the Board made, you know, nine months ago, somehow turned or moved out in the future because something else more pressing came up in the business. So that's a dilemma that we face where there's just the timing of it.

The interconnect, we're Rule 21 compliant, we're plug-and-play into the grid; however, depending on the situation, you're going to get delays. We had with a couple of projects, we actually had some unnecessary delays, and I think there were some politics involved there, but if the utilities could assist in that process, that would again reduce the sales cycle. A typical sales cycle for our projects, between one and a half to two years is basically a sales cycle, so opportunities that we're working on today are opportunities that we're probably going to go off and sell and commission in 2015, maybe in 2016. So it's from a challenge as a small business from a cash flow challenge to invest in growth of our business, that's another dilemma that we have and I would think that, you know, any of the other small businesses that are involved in moving CHP forward to clients, that that is a clear challenge. So if we were to reduce some of the length and time for those sales cycles, I think we'd probably see a lot more companies engaged with us in moving CHP forward because they could make a business out of it.

The last challenge is really the financing aspect of it. A lot of it is just really sort of understanding the technology. I think from a Capstone perspective, I think the bankability of our product has improved, but even with that, the banking community and the cost to fund the projects can actually kill a project. We’ve had a number of brokers come in and they want to add another 15 percent to the transaction, so you go talk about taking the economics, and now you’re looking at a 10-year payback because of the cost of money and cost of funds. And for our mid-market customers, they don’t have readily available two and a half, three million dollars of cash just to go and invest in a project, so financing is going to be a key focus for that.

We’re encouraged about the future. We’ve got an incredible pipeline ahead. We’ve got two hospitals in Southern California that we’ll have commissioned hopefully by the end of the year. We’re dealing with some OSHA compliance issues there and we have some hotels, as well, that we will have coming up by the end of the year commissioned. So there will be a lot more success stories that you’ll be able to choose and pick across industry as an example of how mid-market business is using CHP to improve their bottom line.

MR. DAVIDSON: Thank you, Steve. All right, our next panelist(s) is a tag team, so I’m going to introduce both of them, and then turn things over to both. First is David Erickson and David is a Regulatory Analyst in the Grid Planning and Reliability Section of the Energy Division at the CPUC. Dave focuses primarily on Smart Grid issues, Demand Response and Reliability, and is co-author of CPUC White Papers on Cybersecurity and Regulatory Implications of Microgrids. Prior to the CPUC, Dave was a consultant working with nonprofits and local governments on carbon emission reduction strategies and energy transportation in wastewater and solid waste sectors, and was the lead author in the 2008 Sonoma County Community Climate Action Plan. Dave has a B.S. in Environmental Studies in Planning Energy Management and Design from Sonoma State University.

And the other half of the tag team is Jim Reilly. Jim is the principal of Reilly Associates and has worked as an Independent Consultant in the Energy sector for more than 25 years. God, a lot of us the same age have worked in the energy sector 25 year. (Laughter)

Jim has completed numerous Market Grid and Microgrid projects and workshops for clients in North America, Japan, and Europe. Jim provides consulting services to the U.S. Department of Energy Office of Electricity on Research and Development Planning for Microgrids, and to NIST for Smart Grid Interoperability test bed. Jim holds degrees from Georgetown University and Columbia University. So I guess I turn it over to David first? Okay.

MR. ERICKSON: Okay. Thanks, Keith. I’m focusing on questions 3 and 4 here today, which are more for what’s the direction the state might be taking and where might we address some of these barriers that folks have talked about.

Before I start, I should just say that, although I’m a CPUC employee, my opinions are my own, and I don’t speak for the Commission on matters of policy or any ongoing proceeding.

So today I wanted to just focus on basically three points. The first is that we would like to suggest that you consider CHP as one element of a portfolio, an optimized portfolio, of Distributed Energy Resources, or

DER, that include Demand Response, Electric Vehicles, Storage, as well as intermittent renewables, that are integrated with a control system to serve a well-defined geographic area. So that's really the definition of a Microgrid.

The second is designing an optimized portfolio should be based on the specific thermal and electric load characteristics of a particular area. And that can actually result in a reduction in cost of the various resources, and an improvement in performance.

And then finally, the third point is there are locational benefits to where you place things, and I think we are pretty clear on that. But we're going to be considering that in a lot more detail in an upcoming proceeding in the Commission, which we don't have the procedural framework for it yet, but it's based on what's now called Section 769 of the Public Utilities Code. It was a part of a recent legislation called AB 327, which was a massive omnibus thing that included a lot of different elements, but the Section that became Section 769 calls for the utilities to develop what this Code Section calls Distributed Resources Plans by July of next year, that specify optimal locations for distributed groups of distributed energy resources. And, you know, this obviously includes CHP, and we hope that it may provide or can provide a new procedural framework for a CHP deployment. Those are really the three things I wanted to talk about today.

So if we can go to the next slide, please. I wanted to just put up a definition of a Microgrid because a lot of people, when you say “Microgrid,” they say, “Well, what’s a Microgrid?” So we’re really -- so I’ll let you just look at that, I won’t read it -- but really what it is, we’re trying to advance the notion of an advanced Microgrid. So if you go to the next slide, this is sort of a pictorial representation of an Advanced Microgrid, so you can see at the very top it includes CHP, thermal storage, as you move down you look at the loads, and of course these loads can respond to Demand Response signals, and then at the bottom you see the shedable loads, and throughout you see the distributed resources. Now, these are all potentially distribution connected, right, so potentially they reside on a particular distribution feeder. And there is a control system which is the red box, CC, which actually manages the dispatch of these various resources. So really the key here is to note that this is a portfolio of resources that are managed by a control system, and it can operate in island mode, which is where it is providing all the electricity and potentially thermal energy for that particular set of loads.

So if you go to the next slide, big old long list here, but there are many benefits to approaching electric supply in this way, including thermal energy supply. We see reduced purchases of grid power, reduced purchases of fuel, reduce resource interconnection cost, additional value stream creation, and this is actually a key one, that the Microgrid can actually look to the grid like a multi-function resource, i.e., it can perform as an exporter of power, it can perform as a controllable load, it can either curtail or it can increase consumption, it can drop off the grid altogether. And these are all valuable characteristics.

And this is a little bit of a hint of how some of the economic issues can be addressed that both Keith and Steve mentioned earlier, and also Debbie, regarding departing load and the various charges that are assessed for distributed generation currently.

And then a really key point here also is it can enable the greater integration of renewables, so it can enable the higher penetration of renewables because it can act as essentially a load balancing, or a balancing area through the use of Demand Response.

So that’s where I’d like to transition over to Jim, who is going to talk a little bit about optimization, and how tools can play into the optimization of a Microgrid. So take it away, Jim.

MR. REILLY: Thank you, Dave. I first came to an awareness of the importance of CHP as a renewable energy resource and also as the prime mover for economic value in Microgrid from work that started about 18 months ago with the U.S. Department of Energy, which has quarterly meetings with five of the leading national labs, Sandia, Lawrence Berkeley Lab here in California, and the focus of the work for this work with the National Labs has been to meet the DOE goals for reducing CO_2 emissions and increasing reliability now, and especially resiliency after the weather-related events on the East Coast, which is a primary engine for moving Microgrids forward.

So when I learned from this work with the National Labs that CHP was really really important to the viability of a Microgrid, I said, “Well, where does the evidence come from?” And it came from work that had been done by Lawrence Berkeley Lab in CHP here in California. And the Lawrence Berkeley Lab has developed a tool called DER-CAM to analyze the distributed resources in the context of economics and optimization, CO_2, the many different variables that are optimized. So I discovered that they did a study using this DER-CAM tool where they optimized all energy sources, CHP, solar, storage, even heat pumps, with loads from buildings which in effect was as study of a Microgrid. And the result of this is that it actually gauged the CHP potential in the mid-sized commercial buildings, which were the loads that were identified in this study. So to do this, they filtered a sample containing buildings with electrical peak between 100 kilowatts and five megawatts, from a database containing 2,800 different building types. This resulted in a 138 different DER-CAM building models representing about 35 percent of total consumption in the State of California. The results are shown in this chart, the one in the center. Business as usual for these loads, normal supplies is in blue. The DER-CAM optimization results are stated in the red column there. In this scenario, the results in red were obtained by minimizing costs; now, remember, this is over a range of all these building loads and over a range of all these different resources, generation resources -- including storage here. And they assumed fuel cells, as well, they used SGIP incentives in California, and they had a maximum of a 10-year payback for reasons of being across the board for the analysis, and the results are really interesting in that, just on a cost minimization aspect, it was shown that CHP and photovoltaics got selected by the model as being the cost minimization, the optimal combination, and that in so doing you get a result that’s significant reduction, same time in CO2 emissions. So what do we do about this model in the State of California and what do we do about it to encourage CHP, which is a neglected resource here?

So I've only got three slides, so let's go to the next one here. The modeling tool, just to give you a hint about what it is, we'll tell you what we can do in California in a minute with it, but DER-CAM, as I said, optimization tool, and you can find optimal capacity and dispatch of Distributed Energy Resources to minimize the cost, as we showed in the study, and/or CO_2 emissions in building Microgrids, and you can play with the tradeoffs as you wish, according to where the incentives are if you have cap-and-trade, you don't have cap-and-trade, you get a subsidy, you don't get a subsidy. The optimization problem is solved using a stochastic mixed integer linear programming, and it considers energy management strategies across the range, as well. And the two main branches of this tool are investment and planning and operations, and you might say, well, you can study this, but can you make it work with a CAISO? The answer is definitely, yes. So next.

MR. ERICKSON: All right, sir. Thanks,

Jim. So you could ask how friendly are we to Microgrids today in California, the general advanced Microgrid that we've been talking to, multiple customer, single existing distribution network? The answer is not very. There are many barriers. And we're hoping that Section 769 work will move us in the direction of reducing some of these barriers, or at least shining the light on them and making them more -- making the regulatory framework more friendly to Microgrids. So the next slide, please.

One of the big issues with Microgrids is where do you put them. So we're hoping that, again, as we explore the locational benefits that are being considered in Section 769, we can identify a methodology possibly based on existing CHP, but possibly also based on opportunities for new small scale CHP that are focused on the distribution system areas that provide the lowest interconnection costs, and the most easily sort of accessible loads. So what does that mean? Well, we're not sure exactly yet, but one of the potential solutions here is to start using the currently available modeling tools such as DER-CAM, and there are other tools for distribution system modeling, power flow modeling, that can speed the interconnection process and deal with some of these issues that Steve mentioned.

So we’re hoping to be able to develop a methodology that will model or measure the load profiles, develop hot spots kind of as we indicated here, identify good feeders that have a high locational benefit, and then use a tool to process this data on load, both thermal and electrical, and the distribution system characteristics, to identify “optimal locations.” That’s a possible outcome of Section 769. So Jim will go to his last slide here about how we might use tools to identify these optimal locations and combinations of assets.

MR. REILLY: Okay, so here we know that CHP is highly desirable, if not essential to the viability of Microgrids and for many reasons the value streams that we don’t have time to get into, we know that those Microgrids are important, we know we want to put them into the distribution system, but how do we go about Microgrid-ing the CHP, which is not Microgrid, and now it’s not integrated into the distribution system, it’s not integrated with loads outside of really the location that it is located at? So you go to the DER-CAM tool and you use it to identify the sites that have the highest potential for Microgrids against this optimization model. And if you know the capacity of the CHP facility, you know the load is critical and noncritical, you know where the capacity is over time and during the day, then you know how you're able to manage that with other loads that might be in neighboring areas, or in relationship to the needs of the overall power delivery system. And how the DER-CAM is Microgrided is rather complex, but you include local grid conditions at the point of common coupling, you deal with GIS because that's your way of localizing it, and they're by nature local. And then you have issues of tariff for a particular site. Let's not neglect weather which can be a positive thing because you're balancing the solar in the Microgrid with it, so you're optimizing your available capacity. So you put all this into the mix and you analyze the sites where you have the CHP, and you come up with a ranking. And you know, there's hundreds of these sites, some of which are not even being utilized today and they would have to be upgraded, in some cases you have to put more controls on them, communications with the Distribution System Operator, communications with the ISO, but these are all things that are on the rise and they're going to be here within a couple of years, so let's just leave the tool as let's take advantage and leverage the existing DER-CAM optimization capabilities to create a customized tool to identify CHP with high potential for Microgrid development in the State of California.

MR. ERICKSON: Thanks Jim. So just to wrap up one final reminder, I wanted to please encourage everyone who thinks they might have an interest in this type of work to become a party to whatever proceeding that we generate to address the Section 769 Distribution Resources Plans, that's the key word there. These plans will define optimal locations. Hopefully we'll bring together some of these siloed proceedings, you know, including CHP, including RPS, including some of the other issues that are currently in their silos. Hopefully this will also reveal some of these major barriers that folks have identified here and hopefully deal with some ways of addressing these. And finally, hopefully we'll be able to in this context of an advanced Microgrid to create new markets for CHP and other sets of portfolio resources and tools. So thank you very much.

MR. DAVIDSON: Thank you, David. Thank you, Jim. Okay, we're going to move on to our next panelist, Adam Robinson. Adam is an Account Manager for the Power Generation Division at Solar Turbines, a California-based subsidiary of Caterpillar. Adam covers the Southwestern U.S. and is responsible for developing prospective CHP and BCHP projects, well matched to gas turbine applications. Adam has held prior positions in Application Engineering, Product Management, Marketing, and Finance for the same company. Adam.

MR. ROBINSON: Thank you, Keith. And good morning. Thank you for allowing me to come here and speak to you on this topic, it's one that's near and dear to my heart. I don't have a prepared presentation, but I did prepare some comments for you, which I'll step through. I'm going to introduce some exhibits and I'll make some points along the way, and then conclude with some closing remarks on actionable next steps from my vantage point on how to grow the CHP market in the State of California.

I wanted to relay this to you as more of a story, I suppose, than a direct response to the questions that were posed. With that in mind, you know, we've been talking about these same set of topics for a long time and I'm a big fan of you have to learn where you've come from before you can navigate the path where you want to go. And there's been a number of efforts on that front. I wanted to introduce one of them, which was published in March of 2001, it was the National CHP Roadmap that was introduced by Jim Jamieson, the Executive Director for the U.S. CHP Association. Within this roadmap, the goal of it was to double the capacity and sell capacity of CHP in the United States, looking back at March of 2001 by 2010. So here we are four years past the 2010 date and we're talking about what we need to do to change the way the CHP is going in the State of California. So on that notion, I think it's safe to say that the roadmap fell well short of its goals in California for its part, and that same strategy fell short on its goals, as well.

One of the key objectives within the strategy was to eliminate regulatory and institutional barriers, and I'll site some of those referenced in that same case. It called for uniform interconnection standards, effective and competitively fair utility policies and practices, output-based emission standards, streamline siting and permitting processes and more on a federal level, but equitable, tax provisions. So a lot of the same issues that were cited back in March of 2001 are still very salient points today, significant barriers.

So let me back up and comment on the utility industry, which is extraordinary complex, as we all know. I think just human cognitive limitations drive us to try to simplify and homogenize some of the complexities, but the reality is CHP is being introduced into a very complex market. And I think there's some evidence of this more recently on the topic of greenhouse gas emissions. So in this category, the sub-20 megawatt category of CHP, and Dave, Mel, if you're still here, you touched on this earlier this morning, which was how do we even define what is CHP. So talking about the 20 megawatt and smaller category of CHP, I've highlighted three different distinctions that we should keep in the context of this discussion, the first one is that CHP as it is procured today is typically -- and everybody else, you know, I'm on the gas turbine side of this equation, but other technologies, I think you would agree -- CHP, typically the base load is typically sized for behind the fence, not export, it's not peaking, and it does not create challenges associated with intermittency.

Number two, CHP is not owned by electric utilities, nor utilities typically engaged in Power Purchase Agreements with CHP owners. This contrasts with the renewable technologies and the RPS objectives.

The third point is, and this point has been made earlier today, but CHP is Combined Heat and Power, it's not Combined Power and Heat. Heat is first, a successful project is sized around the thermal requirements first, and that's a big distinction. We tend to dwell on the power side of the equation when we talk about CHP, but by its nature it's a thermal application first.

So point number one that I would make on greenhouse gas emissions, unlike other criteria pollutants such as NO_x and CO, which can be curtailed with the addition of add-on controls in the exhaust stream, the only way to reduce greenhouse gas emissions is through efficiency. And for base load applications with good thermal matches, and I highlight base load applications here because that's typically the application that we're serving, for base load applications CHP ought to be given one of the highest priorities, it's the greatest efficiency application you can serve; your base load application you can serve when you're well matched to a thermal load.

The fact that CHP does provide base load capacity may be what's behind Governor Brown's call for 6,500 new megawatts of CHP by 2030. Will it be 6,500 megawatts? Probably not. If history is an indicator, probably not. But I think more than anything else, what it is it's a call to action.

AB 32 makes no such provisions for prospective CHP projects, instead it's a new cost that's unclear on how to model, so in every case because CHP is not owned by the utilities, it's owned by private investors, the return on investment needs to be evaluated and there's a question mark on the side of AB 32 right now: what exactly are those costs that are going to be introduced by that program?

In this manner, AB 32 has acted as an incremental barrier over those discussed in this document, it's an incremental barrier to new CHP in the state and it should be amended.

Who owns CHP? I touched on this, it's not the utilities. For the most part, it's end users and private investors. So to the question of what are the most significant factors that contribute to the decision to invest in CHP, I generally discuss three different points, one is the economics, two is reliability, and three is sustainability. Of those three, economics will always come first. This is an investment driven application, so economics will win out first.

So when you look back at the same drivers, the efficiencies that create the greenhouse gas reductions, those same drivers of efficiency also create a cost-savings alternative to grid supplied power, electric grid supplied power. So this has kind of been the rub over the years, right? You've got an efficient alternative to electric utility supply and power, or the CHP, I have a thermal load that matches my process so well that I can actually put a generator in front of that heat source and produce power more cost-effectively than I can procure it from the utility. So that's kind of been the battle that we've been faced with over the last several decades.

Another way, looking back through history, there was a big effort, a lot of discussion around the topic of distributed generation. So CHP is a modification from kind of the centralized models, the decentralized model, it fits that category very well, and there was a discussion this is a benefit that produces -- and I think Tom touched on this earlier -- with the notion of how to value the benefit of CHP, it touches on the enhanced reliability and resiliency of the grid. Keith, you touched on it earlier with the earlier panel, as well. So that's a benefit on the side of CHP to keep in mind.

I wanted to make a point on Feed-in

tariffs. AB 1613 has not helped get new CHP installed, contrary to what its objective was originally. It does not assign value to either firm capacity or grid stability, and AB 1613, the Feed-in tariff, and I'll touch on this a little bit later, but it can be -- what a Feed-in tariff does is it will allow sites that can't currently consider CHP to consider CHP. And AB 1613 should be amended accordingly.

What is CHP? And this is a bit of a rhetorical question. I think we can all benefit from a standardized definition, and thanks to SGIP we actually have one. Some of the criteria are set forth in SGIP's less than 20 megawatts, it's greater than 60 percent efficient, and there's a number of other criteria, but it forms the basis for some kind of standardization and consistency in the means at which we define a CHP application. And to that end, with the definition you could consider CHP that meets those criteria as qualifying CHP if you want to think about it that way.

So going back to the Feed-in tariff, the strength of the CHP application is the ability to serve simultaneously both a thermal -- and I'll say thermal first -- thermal and electric loads, but the problem in practice is that the thermal loads and the electric loads don’t always move in lockstep with one another. There may be product limitations that don’t exactly match with an application. So in some cases it may be beneficial to use the utility, use that infinite bus as a means of exporting excess generation, and focusing on operating the equipment that was purchased, or that was applied at a given site at its optimal point, following the thermal side, and load following with that asset, but using the export capability to optimize the efficiency at a given site. So these are all factors I think that weighed in originally when AB 1613 was put together and, you know, we’ve heard from a number of users that it doesn’t work as it is currently structured. So one of the action items to go forward, in my opinion, would be to take a look at that and what can we do to amend it so that it does work.

Building awareness was another key objective that was set forth in this piece, in the National CHP Roadmap, and I wanted to use that as a means of introducing something that was done by the Department of New York City Buildings, which was an Installers Guide and something aimed at Installers because I think anybody who does a deep dive into CHP understands that it’s not easy to get a facility built and installed, and the idea behind the Installers Guide was to highlight some of those issues, and build a greater awareness so that people walk into the development of a potential site with the knowledge of what it takes to get this done. And the resources that are available to help them through the process.

In terms of regulatory challenges, well, before I leave that, I’m not aware and I may be wrong, but I’m not aware of such a document that exists for the State of California, but I think if there was one that was done, it would be a learning process not only for the authors, it could be a multi-agency effort, but it would be a learning process for the authors of the document, but for the readership as well.

So moving on to the regulatory challenges, there are many and several of them were addressed --

MR. HARVILLE: Adam, I think you -- can

you wrap things up in the next minute or so?

MR. ROBINSON: Yeah.

MR. HARVILLE: Thanks.

MR. ROBINSON: Yeah, so okay, let me just go straight to some conclusions here. In terms of actionable next steps, because those are the key takeaways, CHP is aligned with California’s greenhouse gas reduction targets, but AB 32 does not seem to be aligned with CHP. So what we need to do is take a look at that and amend that situation. Definitions for CHP should be created so that when we say CHP we all know that we’re on the same page and there’s a consistent representation of what that means. CHP is heat first and power second. It can be combined cycle, and Dave Mehl touched on that, but the reality is the load is located near the heat sources, and the bulk of the heat sources are not going to have footprints large enough for large combined cycle plants. So the bulk of the center market of the applications is probably in the category of less than 20 megawatts.

I didn’t have time to touch on it, but departing load charges are punitive, and they’re really intended to keep CHP out, so what we need to do is everything that we can to grow CHP, eliminate the departing load charges, or at least, to your point, to ensure that they don't go on into perpetuity. And there's a bill out there, AB 365, that's targeted at just that, eliminating departing load charges. Take a look at that bill, learn about it, and let's see if we can get that passed. And finally, I didn't get a chance to touch on this, but the incentive levels in SGIP are not uniform. Fuel cells are valued at about four and a half times that of CHP, and what we need to do in my opinion is CHP is targeted at base load applications as it stands today; we need CHP in the state and we should establish a greater degree of parity across the technologies within the SGIP Program.

MR. HARVILLE: Thank you, Adam. Keith, if I can -- sorry to cut you off there, just do the time constraints, I just want to let you all know I'm sensing the restlessness, we have one more presenter and then we're just going to need to open it up immediately for public comment following that. Unfortunately there isn't time for much more discussion within the panel, so just hang tight with us, we have one more presenter that Keith will introduce and then we'll have some public comment and we'll break for some lunch. Thank you.

MR. DAVIDSON: Thanks, Jason. Casey Houweling is a farmer first and a CEO second. Casey is a proprietor of Houweling's Tomatoes, a leader in sustainable greenhouse farming. Casey has pioneered new technologies and integrated CHP into his company's business model. Houweling's Tomatoes was founded by Casey's father, Cornelius, and Casey joined the family business in 1976 and by 1985 began to transition from a floral egg nursery to tomato farming. Case owns nurseries in California and British Columbia, and soon to be in Utah. And with that, I'll introduce Casey. And, Linda, in the interest of time, I'm not going to do this, but Linda asked me to just say a few words about the growth of this type of greenhouse in California, and Casey, you might want to touch on that as you're doing it because we see this as a novel application for CHP and one that could promote a lot of growth for CHP in the future. So, Casey.

MR. HOUWELING: All right, thanks, Keith. I'll try and keep this brief without getting too much into the intricate details because there’s a lot of those and you can get bogged down in some of those after a while.

Keith made the introduction, so my history is a long ways back and starts back 35 years already when I first started in the Ag business and growing in the greenhouse sector. And in those days, as every one of us knows energy didn’t matter, water didn’t matter, and a lot of things have changed, particularly in the last 10 years. And it also became a major point to myself of not only that we were in business growing tomatoes, but we were in the business of doing it in a manner where we could leave the least amount of footprint that we possibly could for two reasons, 1) cost, but another reason is, you know, we all have children and we want to leave the world with adequate resources left, on the one hand, and another one not with a ruined environment. So that was kind of what our focus was when we first built the last greenhouse, which we built about five years ago, and we patented it, so it’s a unique piece of technology that we put in, and we built this one in Camarillo, California, and we spent $50 million on it. It was a big project, particularly for a family farm, and we went through this, we designed it in a manner where you used the least amount of energy. We put in PV solar to mitigate the amount of electricity we used, we recaptured heat off our chillers and our water, and we did a whole number of other things which I'm not going to waste too much time, or spend too much time on right now.

And then if I could go to the next slide for a second, please. This is the inside of a greenhouse, a little bit of what it looks like and, you know, it's very expensive technology, it's about a million dollars an acre, we have 125 acres in our California facility alone, so it's big dollars of investment, but it's also very highly productive, 125 acres in this facility here in Camarillo produces as much as 10,000 acres of field tomatoes. And it does it very efficiently, but it's very expensive. And the other negative is it uses a lot of energy in the form of heat. So how do you mitigate that, particularly since the number one waste product in America today is heat? You marry the two up, as we've heard on CHP, it makes so much sense, why is it not happening?

So we went around and I think we were one of the first guys at AB 1613, and for those of you who haven’t gone through that process, and particularly for a farmer, it’s difficult. You know, it’s 350 pages thick, and after I’m on page 2 I’m already cross-eyed, so it’s a tough weight, and you’ve got to tap into a lot of resources and in our case there wasn’t that many out there yet because it hadn’t been done before. We went through the whole process and it took us four years to get it done. And what’s the biggest barriers? Some of us talked about and some of you talked about departing load charges, but in our case the biggest barrier really is you just can’t budget it. You don’t know how long it’s going to take you to build it, you don’t know how much it’s going to cost. And those two factors alone, when I think back on what we started in putting this in, because I thought it was such a simple no brainer that we were going to go out and do it, but if I would have known then what I know now, I don’t think we would have done it. And that’s a tragedy because, in my mind, this is the most efficient way to reduce CO_2 output in

America today. It trumps solar, it trumps a lot of renewables. The only other one that is probably more efficient would be hydro, but particularly in our case it's very very compelling because we use the CO_2, we use the heat, and we also use electricity, but we also export electricity. So we've put all those processes together. And we got it done, but it took a long time. And working with Edison, there were some good people there, but it's an extremely difficult process, one learns after a while that engineering studies take four months, and before you start on the next one, you know, it's gone two months overtime, and you can't start on the next one until that one is done, so it's delay after delay, and meetings after meetings, and when you go to a meeting there's 20 people there. That costs a lot of money and it wastes a lot of time because it's not necessary for it to be that long -- a simple procedure like CHP in our case should be simple. This is not rocket science. This is done -- if you take a country like Holland that has an awful lot of greenhouses, 25 percent of the national electricity is produced at CHPs. Why? Because it's a no brainer. So really, what I think we need is we just need some really good leadership in this arena, somebody that is going to grab the bull by the horns and say "this is what we need to do" and just get it done. Because without leadership, this will never happen. And, you know, if you have a large committee and two people involved, it will also never happen. And you've got to keep the lobbyists a little at bay. I've used lobbyists to get stuff done, but in a lot of cases, you know, you've got to be very very careful. And the advice I could give to the state would be just do that, and just look at it from a CO_2 perspective and what we're really doing. There's so many things that can be done to reduce CO_2 that we're not even touching. And in most cases, they're the easiest ones, the low hanging fruit is getting left unpicked.

We can go to the next one, please. Here is a picture of when we started it. Now, the one we did here, it took us two years after we started this unit before we could export. That's money sitting there just doing nothing. Go onto the next one, please. Oh, go back, sorry. So here is the timeline, so we started in January

2010, and on July 14th we finally got our final settlement out of SCE. So you've got a lot of money tied up, you've got a lot of letter of credits that need to be written out because Edison doesn't risk a penny, everything is covered six ways to Sundays, and you even need to put out the letter of credits to cover their potential tax liability that could come up within the next 10 years. So that's -- I'm just going to keep it short and call it a day.

MR. DAVIDSON: I just, you know, I'll throw out some numbers, Casey, and please correct me. You mentioned the land productivity versus open air farming, but I think you used 40 times less water per pound of product than you do in open air farming in California. Is that an okay number?

MR. HOUWELING: Well, that number you can really play with a lot because it depends where it is, and if it's in the San Joaquin Valley, and what the product is going for. So are you looking at 100 percent marketable product? Are you looking at tonnage coming off a field? Are you looking at processed tomatoes? But in our case, 100 percent of our product ends up in grocery retail and is even fresh, you know, we grow some of the best tomatoes in the world, and with the least amount of carbon footprint, the least amount of water. We use a fraction of the water of what field guys do. And it doesn't come easy, though, let me share you that. All of this innovativeness is difficult and you have to be very very focused on it. And if it wasn't an extreme passion of mine, and if it was up to some corporate CEO, I can assure you it never would have happened.

MR. HARVILLE: All right. Thank you very much, Casey. One small change in plans here, we're going to break for lunch and then do brief public comments when we come back, so that will give you all time to think of your succinct and precise questions over a full belly. So this is putting us a little bit behind schedule, so we would appreciate as concise of a public comment section as we can when we return at 1:45, please. If you can return from lunch at 1:45, we'll start very promptly.

(Recess at 12:49 p.m.)

(Reconvene at 1:51 p.m.)

MR. HARVILLE: I hope you were all able

to get somewhere for lunch quick enough without cooking out there. Just real quickly, is the CPUC back from lunch here? Not to put them on the spot, but…. Not quite yet, all right. They're presenting right after the questions.

All right, I'd like to open up the floor for public comments from the last panel we had on small CHP. I don't think Casey Houweling will be back. Hi.

MS. DERSTINE: Hi. Jen Derstine with Capstone Corporation. And I just wanted to clarify on the panel, so this was a panel directed at small CHP, and I would be interested in the panel's feedback on what barriers or programs are -- what is the difference that small CHP faces versus large CHP for the programs that do exist for CHP in California.

MS. CHANCE: Hi Jen. I think that the small seems to be the sexier and the more attractive, and people seem to be willing to work around the edges for the small, as much problems as you have with small generation that we've discussed today. I think with the big, you get even bigger efficiency gained, but there becomes more of a pushback. So I think the big and boring have every bit as many challenges, if not more, than the sexy, small, niche sort of tire plants, so I think both buckets have barriers that need to be addressed, and both buckets have a lot of promise, too. And I'd sure like to see both buckets addressed.

MR. ERICKSON: I can address that, too, from the regulatory side in this Advanced Microgrid model that we're kind of starting to talk about, that the regulatory barriers primarily have to do with serving multiple customers, you know, multiple meters, with distribution connected resources. We don't have a good model for that right now. It's got to be on the customer side of the meter, or it's got to be wholesale and here in California, as you know, we don't really have a way for -- well, we have community choice aggregation, which basically enables customers of a particular jurisdiction to essentially elect to purchase their power from, you know, somebody else, then the incumbent utility determines that they wish they'd purchased it from, but aside from that there's no real model right now to enable, especially from the Microgrid Operator standpoint, multiple different customers to be supported. The other thing is, if you're talking about a general Microgrid, once again, where you're serving multiple customers, there is the issue of heat distribution, or thermal service distribution. So you know, as I understand it, and I'm not the expert here, but from the standpoint of distribution of the thermal energy, you're kind of talking about a district heat situation, or a district cool situation which involves a fair amount of infrastructure that's not currently available because we don't do that here in California. And, you know, typically our climates are so mild that there hasn't been a compelling need to do it.

Where I see the compelling need, though, is in the de-carbonization of energy generally, and to the extent that we need some alternative to nature gas heating, then I think a district heat model is probably going to become more viable. And you know, there are of course the interconnection costs, how do you straighten that out? Who pays, especially if interconnection upgrades are triggered, how does that get socialized? Does it get socialized? And then there's the whole actually standby charge issue, which is if, say, presume you have a Microgrid Operator say, for example, that it's able to island and run on their own resources for some period of time, do they need to pay standby charges in the sense that, to what degree are they dependent on the existing utility for power in emergency situations? And so what is their responsibility to contribute to the maintenance of the bulk electric system? So those are some of the issues, there are a lot of issues and it's pretty hairy.

MR. ACEVEDO: Let me answer that question. I think the question was what are some of the differences that we see in SGIP between smaller and larger systems? Let me just draw a line that I'm going to say a smaller system is anything that's going to be below 500 kilowatts, and typically one of the key differences is the cost for monitoring. While we believe that monitoring is very important, the cost for monitoring as the kilowatt opportunity decreases, for our product line we can go to a 65 kilowatt unit, but to go drive an SGIP incentive and bring that to the customer, it really -- it's sort of borderline in terms of the value of the incentive versus the cost of what it’s going to involve to monitor the incentive over the five-year period of time.

MR. ERICKSON: Are you talking about from a telemetry standpoint, Steve?

MR. ACEVEDO: It’s the monitoring that’s involved in managing the total efficiency and proving that the installation is meeting the efficiency hurdles that the incentive is meant for. So that’s just a problematic situation.

MS. VAUGHAN: Hi. Beth Vaughan with California Cogeneration Council. Two really really quick questions because I know time is of the essence. One was for David, I was just curious, when do you think this proceeding is going to begin and is there an assigned Commissioner?

MR. ERICKSON: Well, we’ve got to have these distribution resource plans essentially approved by a year from now, July of 2015. So just working backwards, you know, we’re hoping to have a proceeding kicked off by the end of the summer at the latest -- and please don’t hold me to these dates, this is all sort of in the works right now -- it looks like we do have a

Commissioner who is probably interested and that’s Commissioner Picker, although there hasn’t been any particular assigned -- there is no assigned Commissioner at this point because there’s no proceeding, but more than likely it’ll be his office or -- but, again, don’t hold me to that.

MS. VAUGHAN: I won’t hold you to anything, but thank you. That’s good information. And my second question was for Steve. You were refreshing in that you were very positive, which I think helps when we discuss these issues because, you know, CHP as we heard, the development has been rather stagnant, except you were saying that no business is pretty good in terms of your project that you produce. And you talked about you’ve got some projects that will be coming on line, a couple hospitals and some hotels, so one of my questions was, listening to Debbie’s presentation she talked about standby charges and how that’s been a real disincentive when you sit down and do the economics. Is that the case for you with these projects, as well? Has it been as important? And secondly, do you find, therefore, based upon what those rates are, by which utility territory you're building in and developing in, are there some areas that are more favorable than others? Are you seeing more of a build-out in SoCal than you are in PG&E's territory?

MR. ACEVEDO: I do, but I also think that the build-up is just due to the fact that we've been resonating a little longer in that marketplace. We just picked up the Northern California territory about a year and a half to two years ago, so I think we're going to start to see some really cool things up here. We've got some opportunities with some wineries and actually one of those hotels is a boutique hotel in the city, so we'll be coming out with some press releases on those very shortly.

Your first question was --

MS. VAUGHAN: Well, so I've had a number of particularly once things seem to be progressing, there was SGIP, AB 1613 tariff was out, the settlement was done, I would get a lot of calls by developers.

MR. ACEVEDO: Right, so the standby departing load charges, look, they do hamper every one of our projects, they cut into about –

particularly on these smaller end projects, we're looking at, you know, two megawatts and below. Roughly 25 percent of the project cost savings are going to these departing and standby load charges.

MS. VAUGHAN: Okay, that's what I was after.

MR. ACEVEDO: But the projects are compelling enough to convince these mid-market enterprises to go through and invest in it. And there's a number of other intangible benefits that clients get from these projects outside of just the reduced cost of electricity. There's the redundant power ability, so they have secure power that if the Grid goes down their production line is not going to go down. Our technology cleans the power, so we prevent machinery being impacted by power spikes, etc. So you tag in all those benefits in there and it's a good business proposition.

MS. VAUGHAN: Okay, great. Thank you.

MR. ERICKSON: I could just add, too, there that in terms of these other charges, I don't know that we're necessarily going to crack the philosophical nut on who pays these things and how they get paid; but, that being said, I think -- and I didn’t really emphasize this too much -- but Microgrids actually to the extent that CHP is integrated as a resource, you know in a Microgrid, that the Microgrid can generate additional revenue streams that can mitigate these charges to a certain extent. It can provide services to the bulk electric system such as ancillary services, voltage regulation, frequency regulation, those types of things. So that can actually improve the economics significantly, I think. I don’t know if my colleague Jim agrees, but….

MR. REILLY: Well, I do agree and there are a few things that are being worked on now in IEEE1547 is up for total revision now, those physical interconnection rules, and there’s a new IEEE working group for standards for specifications for Microgrid controllers, and that will define the rules for the interconnection of the Microgrid to the distribution utility. And those rules will include checking boxes on certain understandings between the distribution system operator and the owner-operator of the Microgrid, which is probably very closely tied business-wise with the owner of the CHP, as to how they will behave toward one another under certain circumstances. There was an example that came up earlier where you would have excess generation on the utility side, and excess generation in the Microgrid, who sheds the load to keep you into balance. Of course, the standard will say you have to be in balance, you have to have a rule, a decision rule of what you’re going to do under those circumstances that will be written into the interconnection agreement.

MR. ERICKSON: So that’s an economic transaction, an opportunity for an economic transaction.

MR. REILLY: The viewpoint that I’m taking is the utilities need to come to love CHP. And we’re working on a number of things where it can help stability on feeders, to give better power quality to underserved areas, to have some sort of equality between the poor people who live off a feeder that gets a lot of outages, and the ones that live on feeders where they have their own little power plants. So why not give all the benefits of these to the entire grid, all the benefits of reliability, stability, sustainability, and resiliency to the entire Grid, rather than like happens in PV, it just goes to the people who really can afford and they get the net metering benefits. So there's a lot of background studies that are being done to show how these Microgrids with CHP can really help the -- well, let's put it -- the distribution system, whether it's the utility or not, it's the power delivery system that really counts. What the business model is, is for people like Dave to figure out.

MR. HARVILLE: All right, thank you. Do we have any other comments? Okay, great. Then at this point we're going to move on and close the second panel here. And we have a presentation by the CPUC from Damon Franz and Noel Crisostomo. I'll just introduce you to them real quick, they're right over here.

Damon is the Supervisor of the Emerging Procurement Strategy Section at the CPUC, his section implements the CHP policy at the CPUC, including the CHP QF Settlement and the AB 1613 Feed-in Tariff, greenhouse gas policies and programs, Electric Vehicles, and research and development.

Noel is an analyst at CPUC where he works on greenhouse gas emissions reduction policies, including Combined Heat and Power deployment and transportation electrification. Noel has previous experience in Demand Side Management Program design at nonprofits and utilities, and holds BS and MS Degrees in Energy and Earth Systems from Stanford. And guys, just real quick before you start, if I could just have the folks, when they’re done there, just come on up who are taking part in the rest of it today, just come up at once and that way we won’t have to worry about so much sitting down and getting up, and all that. Okay, take it away. Thank you.

MR. FRANZ: Thanks, Jason. And thanks to the CEC for holding this workshop. I think this is a very important event and developing good policy around CHP, I think, is challenging due to the sort of very variable nature of the resource and the different sort of types of values that you get out of it. But the CPUC is working very hard to try to promote it in a reasonable cost-effective and productive way, and so we’re happy that you’re having events like this.

I’m Damon Franz, I’m the Supervisor of a Section in the Energy Division, that’s a section of Analysts that provides analytical support on a number of different issues, including CHP. We don’t cover the Self Generation Incentive Program and we don’t really deal much with rates, so we don’t get too involved with things like non-bypassable charges. Most of our activity right now is implementing the CHP QF Settlement. There has not been an open proceeding at the CPUC since the settlement was approved on CHP, so that’s really been the primary venue for CHP policy moving forward, however, beginning this year we will have an open venue in the Long Term Procurement Proceeding that I’m going to talk about in a little bit. But first I want to introduce my analyst, Noel Crisostomo. A lot of you know him, and he has been great about really trying to make the settlement work well, to keep on top of it, to make sure that the utilities are pursuing the right types of contracts. So Noel is going to give an update on the progress of the settlement right now.

MR. CRISOSTOMO: So just an agenda item, so we’ll be talking about the three year quest for offers that our in various stages across the three utilities, and the timelines that the utilities have taken thus far in the CHP-only request for offers.

For those that are less familiar with the settlement, the RFOs were established in 2011 with the CHP Program and it set forth two targets, 3,000 megawatts of CHP capacity, and that includes the re-contracting of existing facilities, changes in operations, potential terminations of existing inefficient CHP facilities, but also new building of capacity or powering of existing facilities.

Next, we'll go into the major events in the megawatt and GHG procurement targets. This is not supposed to be a comprehensive overview of everything that has happened in the settlement since it was approved in November of 2011, but just some of the procurement snapshots that are captured in our semi-annual reports and these will be available on our website, and we have a link at the end. And next, Damon will conclude with a preview of how we are going to be considering CHP in the current LTTP.

So I know this is an eye chart, but this is supposed to give you a sense of the type of oversight activities and the processes that the utilities generally have been taking for the RFOs. Each of the three RFOs consists of a launch where the utilities are completing an outreach program to the CHP industry to have them understand how the RFOs will be run. They will solicit offers from them, short lists, select offers that are economic and help progress the utilities toward their two goals.

During this time, the utilities will come to us and brief the PUC on the evaluation methodologies that they're using, how they're valuing the facilities, the strategies that they're taking to shortlist and make sure that they're progressing towards their goals. And this will continue throughout the negotiation process.

Next, the utilities will file Advice Letters with the Commission and, after considering the Advice Letters in terms of the CHP settlement and its counting rules and the CHP's eligibility for participating in the program, the PUC will write a resolution either approving or denying the proposed contract.

One of the takeaways that you have to come from this chart is that PG&E and Edison completed RF01 in approximately the same amount of time, just about a year, from launching to executing and filing their last contract with the Commission. However, if you notice, the launch of RFO 2 for PG&E was several months ahead of Edison and I'll be going into greater detail about why this happened. But in short, due to the procurement choices Edison had taken during RFO 1, they were unwilling to go forward with launching RFO 2. While PG&E had a similar problem, they went forward shortly after filing the transaction with the PUC with launching RFO 2, so you can see that they filed their last transaction in almost January of 2012, and a few months later continued to launch RFO 2.

Currently, were we are, we have seven Advice Letters before the Commission and I'll be discussing which of the contracts that we have before us right now, two at PG&E and five at Edison. For San Diego, currently there is no RFO 2 contract before us, and I'll be going into detail why that is.

And then for RFO 3, currently PG&E is

beyond the shortlisting phase, is continuing to negotiate with counterparties, and Edison and San Diego have not launched RFO 3 yet due to their local capacity requirement RFOs which were authorized last year in the LTPP, in part to replace the capacity from the SONGS outage.

As you heard earlier during some of the other presentations, CHP is listed as a preferred resource, and is eligible to participate in these LCR RFOs.

So each of these next three slides will go into detail about some of the major procurement events and, again, it’s not supposed to be comprehensive of all the transactions that the utilities have completed thus far, but each of those dots is the progress at the six-month semi-annual reports that the utilities have been submitting to us since March of 2012. And we can track the procurement progress toward the megawatt goals on the X axis and the settlement greenhouse gas emissions reduction target on the Y axis. So you can see each of the RFOs has a specific megawatt target and cumulatively for PG&E, for example, it’s 1,387 megawatts and 2.16 million metric tons by 2020, which is inclusive of both the initial program period which began in November of 2011, and will be completed in November of 2015. The second program period which will be the focus of the Long Term Procurement Plan will continue at that point until December 31, 2020.

So between the first and second reporting periods, one of the major contracts that was executed was the Los Medanos Energy Center facility from RFO 1. This reporting schedule was completed before the RFO 1 facilities were completely executed and transacted, so the Kern River Cogeneration facility and the Oroville facility were latecomers in this reporting cycle.

Commission Resolution E4529 was in response to the Los Medanos contract because the Commission deemed that the settlement did not envision to include capacity only contracts, which LMEC was. So during this first and second period of 2013, we saw a reduction in the amount of capacity that PG&E had progressed toward their megawatt target. So that clarification was guiding PG&E and Edison as you'll see on the next slide, to not accept capacity only offers in the future.

This last point reflects RFO 2, which the Commission is currently reviewing. The Five Brothers Facilities, which are dispatchable utility pre-scheduled facilities, but also the hybrid offering from Midway Sunset and the Veresen Ripon facility which contributes greenhouse gas only towards the greenhouse gas emissions goal.

So overall, PG&E is nearly complete with megawatt target C and over half, I think about 60 percent of the total greenhouse gas emissions reduction target.

Edison is a little bit of a different story, but some of the same issues applied with the RFO 1 facility because both Los Medanos and Gilroy were capacity only contracts. So you can see in this Resolution E4569, there was some loss in the progress toward the megawatt goal, pursuant to that Commission clarification, but also from RFO 1 the Harbor facility, which was determined to not be compliant with the FERC requirements for new CHP facilities resulted in the rejection of that advice letter to the Commission.

Currently, CHP RFO 2 is not shown on this graph, but the large jump in progress in the GHG goal is primarily due to the re-contracting of a repowered facility, the Ace Phoenix Cogeneration Plant, which derives all of its GHG coming from the refueling of coal to natural gas, so that was executed before our last reporting cycle, but again, this graph does not show the swath of existing facilities that Edison procured in the spring and has filed with us currently, so existing facilities include Berry University, US Borax, the New Indy Facilities, and I guess technically Elk Hills is a new facility because it became a QF after the Energy Policy Act of 2005, but there's also another new facility, the Native American Energy Resources, I believe, EOR facility. So Edison is going to approach megawatt target B once these RFO 2 facilities are captured in this next reporting cycle, but will be at least a third of the way toward the GHG target.

San Diego has yet another different story. The story here is much different because San Diego has a much smaller procurement target on the order of 211 megawatts instead of around 1,400 for PG&E and Edison. So a single contract was procured during RFO 1, the Jasmin facility, and that would bring San Diego really close to their Target A, in addition with a few other pending facilities, but very substantially towards the Greenhouse Gas Emissions Reduction target.

The Goal Line facility was recently submitted to the PUC, but a few months ago in the spring, Jasmin was withdrawn by San Diego due to a contract default, so the terms of the contract were not met and this new facility which was proposing to again refuel a coal facility to a biomass UR facility did not meet the terms of San Diego's agreement. So with that withdrawal, San Diego had substantial progress toward both the megawatt and GHG goals lost.

So with that, Damon will present on the LTPP, but I would encourage you if you're interested in the CHP procurement data to visit our website and download the latest report and template.

MR. FRANZ: Thanks, Noel. So as I mentioned earlier, we have a new venue for considering CHP policies before the Commission. This is sort of the first opportunity to make new policy on CHP since AB 1613, and some of those other proceedings were closed. And this is a rulemaking assisted to Commissioner Picker and Administrative Law Judge Gamson, it’s brand new, it opened last year, on May 6th there was a ruling that essentially just said we’re going to identify issues regarding CHP to address in the proceeding, so this will be the opportunity for parties to file formal comments before the Commission and let us know your views on what we should do. And this was sort of teed up in the CHP QF Settlement, which sort of envisioned that there would be two program periods, one with a megawatt goal, and the second one with a GHG goal, so the first one was slated to end in 2015 and it was envisioned that in the 2015 Long Term Procurement Proceeding, we would revisit the settlement, see how it’s working, and consider any changes that we might need to make. And those sort of include, you know, did the IOUs meet their megawatt targets, and if not should we require them to procure more CHP in the second program period? Did anything change regarding our assumptions that went into the methodology for calculating emissions reductions like the avoided grid emissions, or boiler efficiencies, things like that, and then technical and economic potential for sort of new CHP. So you can look through the CHP QF Settlement, it's on our website, and there's the sections that are teed up for the LTPP are identified in our presentation. And that doesn't necessarily mean that the LTPP has to be limited to only those issues, if there are other issues that parties want to tee up, they're welcome to make the case before the Commission that they should be considered. And you can expect a ruling probably sometime this summer, kind of fleshing out a little bit more what the assigned Commissioner and what the Administrative Law Judge sort of see as the issues that they would like to consider, and sort of the questions that they would like to get party comment on. So if you're interested in these issues, I encourage you to get on the service list for the proceeding. You can do that on our website. It's R.13-12-010, and you'll get all of the documents that we put out regarding not only CHP, but all procurement-related issues.

And that's my presentation. Here is my contact information, my cell phone, Noel

Crisostomo. I want to thank Casey Houweling for not bringing any tomatoes to throw at us for the problems we had with the AB 1613 Feed-in tariff. You're welcome to contact my cell phone, though a lot of times the issues with implementing things like interconnection and engineering studies are kind of inscribed in the PU Code and State law, and there's not much we can do about them, but we're always happy to try to help speed some of those things along and smooth out the issues with stuff like that, we're sorry to hear about the trouble. So thanks for your time.

MR. HARVILLE: Great. Thank you very much. I'm going to ask you two to stay put for just a second so we can have some brief questions, but beforehand can I just have everyone who is going to be participating in the third panel today come up and take a seat? Some of you are presenting papers and I think just for the sake of time, we're going to have you present them from your seat so we don't have all the back and forth walking time. So just feel free to take a seat wherever you're comfortable, please. And while they're taking their seats, do we have any questions from the audience for the CPUC?

Comments? Keith.
MR. DAVIDSON: Just one that occurred to me. I probably know the answer, but with the cost of CO_2, I mean, that's not (inaudible)?
MR. FRANZ: That's actually a great question. That's sort of one of the issues that we are teed up to address, and because there hadn't been any contracts until very recently, we hadn't done it and we've been sort of all hands on deck implementing the other settlement issues, but we are bringing some folks together from both the CHP parties and the utilities in the next couple weeks, I think, to try to get an answer on that. So that will be addressed fairly soon, who takes responsibility for those costs.
MR. HARVILLE: Thank you. Tom?
MR. BEACH: Tom Beach for the California Cogeneration Council. I just wanted to ask a question to clarify one aspect of the greenhouse gas accounting under the QF CHP settlement. Isn't it true that there's the possibility that if existing efficient CHP is not re-contracted during the first program period, and then ceases operating as CHP, that you could get some deficits that would count to reduce the utility's

progress towards the GHG targets?

MR. FRANZ: Yeah, that’s correct. And we were just having a conversation about that over lunch that, the way the settlement is written, if efficient CHP shuts down, it does count as a debit and I think we may need to address in the LTTP sort of, you know, how do you avoid that from happening in the first place because, you know, it doesn’t make sense to have something shut down and then potentially you could then get a credit back for just re-contracting with it. So that’s something we might need to get some clarification on.

MR. BEACH: Thank you.

MR. ALCANTAR: Michael Alcantar. Would you help me, is there an advice letter filing for Phoenix? And is there an advice letter filing for Veresen Ripon?

MR. CRISOSTOMO: The Phoenix advice letter has not come in yet, so this is just a snapshot of the executed contracts and Edison has not filed that yet.

MR. ALCANTAR: Okay.

MR. CRISOSTOMO: Ripon is a short term contract, less than five years, so that was coming through the QCR, Quarterly Compliance Report.

MR. ALCANTAR: Right, okay. And did I misunderstand it, or did you post the latest --

MR. CRISOSTOMO: That's going through our IT guys and it takes them a few days, but that will be up in the next.

MR. HARVILLE: Thank you. Any other questions? All right, then we'll move on to the next section of the workshop here. We're going to have a series of presentations and I just want to ask all of the presenters for your help here, I think we all know we're running a little bit behind, so if you could please keep your presentations to the 10 minutes. And like I said, I have in my hand a little sign here and I'll try to flash to you if you're getting close, but if there's anything you can do to help get back on track, I'd appreciate it.

So to start off, we have a presentation by Sonika Choudhary and Ray Williams of Pacific Gas and Electric.

Ray Williams is the Director of Long Term Energy Policy in the Energy Procurement Department at PG&E. His current focus includes greenhouse gas policy, as well as policy matters addressing Combined Heat and Power Procurement and Community Choice Aggregation. Ray holds a Bachelor of Arts in Geography from Clark University and a Master's of Science in Civil Engineering from Stanford.

Sonika is a Senior Analyst for the Long Term Energy Policy Team of the Energy Procurement Department of PG&E. She joined PG&E in 2012 and her current work includes conducting greenhouse gas and combined heat and power technology policy analysis. Prior to PG&E, Sonika worked in India with a nonprofit based in New Delhi, helped plan and monitor distributed generation plants for rural electrification. She holds a BS in Electrical Engineering from IIT Delhi in India and an MS in Environmental Science from the University of Michigan Ann Arbor. So take it away, thank you.

MR. WILLIAMS: Thank you, Jason. So I'll introduce the paper. Sonika, who really did most of the work, will sort of walk through the analysis, and then I'll have some concluding remarks. And in between all of that, we'll try to get done in 10 minutes or less.

So just turning to the next page, in essence what we tried to do in this paper is to set up a framework for evaluating the GHG reducing impact of natural gas-fired topping cycle at Combined Heat and Power facilities. So in essence, that’s a comparison of separate heat and power to combined heat and power. For separate heat and power, we reviewed a range of boiler efficiencies and marginal emissions rates and we also looked at on the CHP side a range of performances for topping cycle CHP.

What we did not cover is the GHG impact from bottom cycling CHP, we can discuss that maybe during the panel, or renewable fired CHP. And we did not look from a utility customer perspective at other CHP attributes that are important and provide value, and that includes system reliability, operating flexibility, and what we term affordability, or its contribution towards keeping our customers’ rates in an affordable place.

Okay, at this point, having given the introduction, Sonika gets to do the hard stuff. So ahead, Sonika.

MS. CHOUDHARY: Thanks, Ray. Next slide.

So starting with a simple concept, I think this morning we heard a lot about the GHG benefits of CHP, and this is how we look for our gas-fired topping cycle, which is also known as conventional CHP, the majority of the CHP in California. So on the left-hand side, it’s the direct emissions from the CHP facility, and on the right-hand side of the equation is if they produce the same amount of heat and electricity output, how much emissions would be from separate heat and power sources, and separate heat can be an industrial boiler, or it can be a boiler related to other thermal application. And on the electricity side, it’s displaced emissions from the electric grid, which would have been consumed instead of producing CHP electricity on-site. Next slide.

So I’m not going into the details of all the equations which is out there, but I’m talking the formula of the direct GHG emissions. You can convert this into a simple X Y diamond, a straight-line equation, and if you can go to the next slide, so that’s how it looks pictorially, the same formula of the direct emissions from CHP in separate heat and power.

So on the Y axis, what this graph is presenting is thermal efficiency, and that is how much used thermal output per unit of fuel input, and on the X axis it's the electrical efficiency. And the red line is what I'm calling an example, a double-benchmark line. And if the CHP emissions are less than this double-benchmark line, coordinates will fall on the upper-hand side of this equation and it will be emissions reducing, but if CHP is not performing well, either in thermal efficiency or electrical efficiency, it will fall below this double-benchmark line and would be classified as emitting CHP. So that is the simple conceptual framework of how to look at the efficiency of gas-fired CHP, one way to look at it.

And what this framework provides is like what's the greenhouse gas performance metric and if CHP is reducing or not, and it's currently being used in QF CHP Settlement. Next slide.

So what we did in our paper which we presented in the conference last year was just look at the public data sources and what's the benchmark of their Combined Heat and Power Performance. And for the technology types we analyzed, it was a large area all from small CHP to large CHP, we didn’t do any differentiation based on the technology size type. And these are the technologies you see in the CEC commissioned ICF report, the 2012 report, which they used for the potential study in California.

And in terms of technology performance, we considered two scenarios, and the one scenario I labeled Design Performance, which is pretty much like the same specification we get from the manufacturers and in the timeframe of 2016 to 2020, how the CHP performance looks for all the technology types that are in the potential study. And the other thing we have in consideration I labeled as Operational Performance, and this is from the experience from the smaller SHP program design that many of the CHP -- they didn’t do performance, they were designed to perform, so discounted on the two bottom meters, one is useful thermal output and the other one is electrical output, and based on the SHP report. And I would like to note here that we don’t have similar datasets for larger CHP which are out there in California; PG&E has limited visibility to Air Resources Board Mandatory GHG Reports, so we created this Operational Performance as a possible scenario and, as policymakers we need to pay more attention, and it's one of the critical areas for future research.

And on Avoided Grid Emissions sites, again, we used all the public data sources which are out there at the national level, referring to the U.S. EPA Calculator, and in California going to the CPUC 2010 Greenhouse Gas Emissions Calculator, and then we did one theoretical scenario of adjusting it for the RPS and the T&D losses for the onsite CHP, which we can maybe discuss later, how it is a theoretical concept and might not be implying what is actually going on in the Grid side.

And for the Avoided Boiler Efficiency, we looked at two benchmarks, one is 80 percent boiler efficiency benchmark, which is right now in the QF CHP Settlement and other places, and 85 percent representative of boiler efficiency based on Air Resources Board Cap-and-Trade Regulations where they have this for relatively efficient industrial boiler. Next slide.

So this is how like the same Separate Heat and Power Benchmarks translates to the same dimensional, two-dimensional plot I disclosed earlier. The dotted blue line is the U.S. double benchmark, the red one is the California with the GHG Calculator from the PUC, and 85 percent boiler efficiency, and the third scenario is adjusted for RPS. Next.

And this is how just a design performance in the timeframe of 2016 to 2020 looks for all the different kinds of CHP and, as you can see, we didn’t differentiate it by any technology size or anything. Next slide.

And that’s how directionally it moves in the other direction if the CHP performance are not operating as they are designed to operate because of like many reasons and it’s an area for the research. So Ray, you can go forward from here.

MR. WILLIAMS: So again, what we used was representative of public data that was available to PG&E. This was not an attempt to say we think there’s going to be more large CHP or more small CHP going forward, but just to show sample results for various CHP technologies against, you know, various benchmarks.

And I just did want to address the RPS 33 percent adjustment at this point, and this is sort of moving from sort of a study to just an observation going forward. And some of you, we’ve presented our carbon metric work to you and you’ll note that, if you remember, we used something more like that red line or that middle line, and did not include that RPS adjustment line as part of looking at our metric. And I know that’s an issue in discussion, I know that the PUC has used that in various ways, and I think we should think about that as kind of an open issue in California as you move from RPS to more of a central policy around greenhouse gas, so I just wanted to highlight that particular policy issue because it obviously has a pretty big impact on topping cycle natural gas-fired CHP.

Okay, just to quickly summarize: in California natural gas is on the margin, you could say both for boilers as well as for the grid. This is topping cycle natural gas-fired CHP. In this instance where the same gas is being used, it’s really important to look very carefully at the Grid and at the operation of the CHP facility to get a good feel for the extent to which it reduces greenhouse gas naturally with coal in the margin. Nationally it’s a different story.

Finally, I think we probably need to look at renewable or bottom cycling CHP differently than applying this particular benchmark, and I think that’s another open issue.

MR. HARVILLE: Great. Thank you very much and I appreciate your sensitivity to the time. Our next presenter is Joel Bluestein. He was on the first panel, but I didn’t get the opportunity to actually introduce him, we got straight into conversation. So I’ll just tell you Joel is a Senior Vice President at ICF International with over 30 years’ experience in the Energy and Environmental arenas. Joel has been tracking and forecasting the development of CHP markets for over 20 years and has authored numerous reports on the history, development and potential for CHP. Joel also works with the EPA’s CHP partnership, DOE CHP programs, and CHP Project and Equipment Developers on regulatory and market issues that affect the future of CHP. Joel holds a degree in Mechanical Engineering from MIT. Take it away, Joel. Thank you.

MR. BLUESTEIN: Thank you. Thanks for inviting me. I'm here representing work that we've done for the U.S. EPA CHP Partnership. So let's go to the next slide.

EPA asked us to look at the paper that Ray and Sonika had written, which we did, and we're just going to highlight a few things, some context regarding the California market, presenting the information in a slightly different format that may be more transparent or may not be, it depends on your view of the world. And also talk about how some of those factors that Ray and Sonica talked about in terms of the boiler efficiency, the thermal utilization, and so on, how they change the results. So let's go to the next slide.

Just the California CHP capacity, we track CHP capacity nationally for the Department of Energy in Oakridge National Lab. That database is online and you can Google CHP Capacity Database and look it up. It's largely based on information from the U.S. Energy Information Administration, but we look at a lot of other sources, as well. And so you can see why everyone is talking about natural gas CHP in

California, although there are other fuels as well, but certainly that's the vast majority. Next slide.

If you look only at the CHP capacity by technology, you see it's mostly combustion turbine and combined cycle, which is also combustion turbine. Next slide.

And then if you break it down by technology and total capacity, so this is in megawatts, it doesn't say that, but you can see most of the capacity is larger, over 20 megawatts, and combustion turbine and combined cycle, that's not really surprising, but it gives you some numbers there to go on.

So although we do have a lot of different systems, the majority of the capacity is in those categories. Next slide.

The other issue is sales to the grid, and we have some data for about 90 percent of the capacity, and for the systems for which we have data, according to what's reported, and again this is reported by the operators mostly to the EIA. Most of the larger CT Combined Cycle Systems are selling some amount of power to the grid, it's about even for the engine systems and much less for the micro turbines, and none reported for the Fuel Cells.

So just a couple of the key assumptions, and you’ll see in a minute why these are so important, but Sonika mentioned that they looked at kind of the design values, and then some of the operational values that were reported by small systems at an earlier time in the program, so their thermal utilization, and this is how much of the thermal energy that is produced is used, or some representation of that. And there are two cases, they looked at a range from 64 percent to 100 percent. We looked at 90 percent, which is more typical for large systems that are base loaded, and certainly for the design. Somebody said earlier if you’re doing CHP, you want to have high utilization and good thermal load, that’s what makes CHP cost-effective, though if you were going to have 50 percent utilization, it would probably be a bad bet for a CHP system.

And then the efficiency of the boiler, the separate boiler that you’re displacing, if you didn’t have the CHP, you’d have a boiler generating steam, what’s the efficiency of that boiler? And this is definitely an area for research, there's really little good information on boiler efficiency in industrial applications, as strange as that may seem, but the numbers that we typically see from operators are more in the high 70's to low 80's, and 85 is pretty high in our experience. That said, if you're looking on the very small side, for example residential heating systems that are more efficient, but again looking at the majority of the capacity in California, which is on the large size, we use 80 percent.

And then there was also an assumption in Ray and Sonika's paper about performance degradation over time for the CHP system, which I won't get into except to say that we didn't include that in our calculation. Okay, next slide.

So here is how we showed it a little differently. We basically are showing the emissions per megawatt hour for each system, so you have the systems across the bottom, and the CO_2 emissions in tons per megawatt hour on the axis and, again, we're comparing the same thing which is the emissions of the CHP system compared to the sum of the grid emissions and the emissions from the boiler that you are displacing.

So the first piece is the emissions from the CHP system, and that’s easy, you have the CHP system, you have the efficiency and how much fuel they’re using, and so it’s easy to calculate the emissions, and so these Xs represent the emissions, it’s basically the efficiency, the electrical efficiency of that system. By and large, you know, the larger systems are more efficient, so you have that downward sloping trend for each technology. And these numbers never change, okay? So with just one set of technology assumptions, so these are the emissions from a CHP system, they don’t change. Next slide.

And so the first thing you have is the electricity from the grid that’s displaced. We have one marginal grid emission factor, same factor, this is the 2020 California marginal grid emissions that Ray and Sonika used, which are from some California modeling. And it’s per megawatt hour, so it is what it is and it doesn’t change either because for any megawatt hour that you displace, it's always the same value in this case because we're only using that 2020 marginal grid emission factor. So you have the CHP emissions, you have the grid displacement per megawatt hour, obviously the CHP is higher, it's similar to the chart that Keith Davidson showed earlier. On a purely electric basis, the CHP system is higher, but we are missing that last piece which is the displaced boiler emissions. So next slide.

And so here, this is where it gets interesting because this is where the different assumptions have an effect. So this is Ray and Sonika's pessimistic case, it's the low thermal utilization and high boiler efficiency, and you can see the green bar is the boiler emissions. And what happens when you, for example, the implication of low thermal utilization is you're displacing less boiler usage, right, so the displaced boiler is running less, so it emits less, so the separate heat and power emissions are lower, and if it's a very efficient boiler, it's emitting less because it's very efficient. So those two assumptions have an important effect because you're essentially seeing less emissions from the displaced boiler because you're creating less steam, and you're doing it more efficiently. And in that case, some of the CHP systems are still emitting higher, which in the other chart, which is very elegant, I have to say, but not as transparent to me, it means those dots would be to the right of the slanting line.

So now, if you go to the next slide, and now here we're saying 80 percent boiler efficiency, so what we would think is a more typical boiler efficiency, and a higher thermal utilization, so we're using most of the thermal from the CHP system, and we are generating it in the alternative boiler at a lower efficiency. So therefore the emissions from the displaced boiler, the green bars, are higher. The Xs didn't move, the power bars didn't move, just the green bars got bigger because we're generating more steam and we're doing it a little less efficiently. And in this case, then, what we would say is a more typical set of assumptions, you can see that the CHP has lower emissions in all of the cases.

In the slides and in the paper that we did, we also looked at the RPS case with the 30 percent discount on the grid emissions and when you do that, the power emissions line comes down and then you have some CHP systems that are higher. I think I address that on the next slide. Yeah. So, you know, I would agree with Ray, conceptually, directionally it seems correct, but I'm also not sure that it is the best way to show the effect of the RPS. And the other question is kind of more broadly, what is the marginal emission rate? We just used the same modeling that Ray and Sonika had used, but we looked at some other modeling of California, including the analysis of the 50 percent RPS that suggests that there's potentially peaking units on line all the time because of the variability of the renewable component, which would lead, we think, to a higher marginal grid rate than is shown in the numbers that we used and Ray used. So we think that's another area for further research. Next slide.

MR. HARVILLE: Joel, could you wrap it up, please?

MR. BLUESTEIN: Yes, I'm sorry, I'm wrapping it up right now. So a couple items, you know, the same issue, what is actual system performance on utilization, boiler efficiency, marginal grid emission rates, and treatment of the RPS. Next slide.

We think most CHP systems are going to be sized to meet their base load thermal demand, which we’ve heard earlier, so higher utilization is a reasonable assumption, especially for the larger systems. We think, you know, assuming a very high boiler efficiency is not going to give you realistic results. And the next slide is my last slide.

We’d like to look more at the avoided grid emissions, not efficiency, which I guess we’re going to hear about and talk more about the RPS adjustment. So I’ll leave it there.

MR. HARVILLE: Great. Thank you. Sorry to have to rush you along there.

All right, we have one final paper in this segment here that we’re going to have presented. It’s being presented by Cliff Rochlin. He’s a Market Advisor to the Energy and Capacity Markets Department at Southern California Gas Company, where his primary task is to monitor and evaluate the changes in the electricity industry. Cliff has worked for SoCal

Gas for the past 23 years and is a member of the Rutgers Center for Research and Regulated Industries Western Conference Organizing Committee. That’s a mouthful, huh? Cliff received a PhD in Economics from U.C. Santa Barbara. Thank you, Cliff.

MR. ROCHLIN: Thank you. This paper is kind of a reaction to what Ray just presented and another paper that was presented a couple years ago at the Ceres Conference by Carl Silsbee. So we’re trying to present now a comprehensive way to evaluate GHG reduction, the reduction potential of CHP. So it’s a counter example to other piecemeal methods to evaluate CHP’s ability to decrease GHG emissions. Next slide.

The first bullet is really important for California because as the grid becomes more efficient you use less fuel. And in California, with the once-through cooling, you’re going to be removing over 13,000 megawatts of old gas-fired steam boilers, large generators. So that’s an important point, that’s the cleaner aspect. The Renewable Portfolio Standard, the state is going to meet the 33 percent RPS in 2020, and the second bullet is the ICF issue that they pointed out, that is, every time you put a megawatt of CHP in, you reduce demand by one megawatt, and therefore you would need to have one less megawatt of renewable resources. So that means from ICF's point of view that for every megawatt of CHP, you would only get two-thirds the benefit of reducing the marginal fossil fuel generator. And then finally, what this all means is, as the last bullet says, the GHG intensity is declining in the California Grid. Next slide.

This is a table that was from the Silsbee paper that I mentioned, and it starts in the mid-1980's, that I don't have up there, but it's 2,200 megawatts of SCE CHP. And this was at that time expected to result in a 3.9 million metric ton reduction in GHG. And you see as the GHG intensity falls, the ability of CHP to reduce GHG falls also. And I added the last column, the last column is the EPA Clean Power Plant, this just came out June 2nd, and it basically says that if you use the Silbee approach, his formula, CHP would actually result in increasing GHG emissions. Okay, now the EPA CPP plan, California is on target to meet that without having to do anything differently, basically the

RPS, the Cap-and-Trade, the energy efficiency, all the programs are on line to meet those requirements. Next slide.

I will quote Ray Williams because this is the genesis, really, of what we tried to do with a comprehensive understanding of how CHP and GHG works. “Estimating the energy and emissions displaced by CHP requires an estimate of the nature of generation displaced by the CHP system. Accurate estimates can be made using a Power System Dispatch Model to determine how emissions for generation in a specific region are impacted by the shift in the System Demand Curve and the generation mix resulting from the addition of the new CHP system.” So basically we’re using a production cost simulation model, next slide, to try to answer the question of how CHP interacts both on the demand side, as well as on the supply side.

We used the Production Simulation Model and the assumptions that were used in the 2014 California Gas Report. So that’s what the first two little paragraphs are up there. The important thing are the last two bullets. The 33 percent RPS Standard will be fully implemented in

2021. So that's why we're using the year of 2021 to do this evaluation. And of the 13,359 megawatts of once-through cooling, 11,744 are going to be removed. So that's the world that we're going to run this simulation in. Next slide.

So we use the ICF study that they did in 2012 for the CEC talking about CHP potential market penetration, and so we're using their medium case scenario. And here we're adding 2,670 megawatts total CHP, broken into two groups, the large is 1,576 and the small, less than 20 megawatts, was 1,093 megawatts, about a 60-40 split. It also showed us the percent of the CHP to put into each area, each of the four utilities that we have up there. And the small CHP was broken into four different categories, and you can see the list up there. Next slide.

My co-author is an expert in small CHP systems and he created a prototype for each of the four small category systems that ICF talked about, and that's what this is a picture of. Next slide.

This is the load shape of those small systems, and we would scale it up to meet the

1,093 megawatts. The important point of this, we made the assumption that all small CHP would not be exported to the grid, it's just to meet its own native load, and so that means it would be avoiding 6.9 percent transmission and distribution loss, as I use the same number that Ray used. Next slide.

This is where we used some confidential information and I have some SoCal Gas. We monitored 13 large co-generation facilities greater than 20 megawatts. And that capacity is 895 megawatts. And we see that there's two distinct shapes up here, there's the bottom one which shows that there is clearly a daily and weekly pattern, and then there's the top load which is the one in green, which is more like a base load, they're on all the time. And you put the two together and you get the blue line on the top. Okay? Go back, thank you. That's gas. So I took this gas information and I compared it to the gas information on the QFERs and it was a pretty close match, so I felt comfortable taking this and creating a monthly percent for each different CHP customer, and then using the electric load from QFERs to get an electrical model, so we have the electrical load shape for these 13 QFs. And we needed one more other piece of confidential information, the amount of the large CHP that's exported to the Grid, and that turned out to be around 37.3 percent on an annual basis. Next slide.

So this is the result of the production simulation model, this is just the CHP part. This is the amount of the fuel savings, if you will, and fuel use by the CHP that's not exported to the Grid. And so you see that there's the increase in CHP, which is the increase in the CO_2 emissions, and then the T&D savings and the boiler fuel savings. Next slide.

So as an output from the model, we find out the total amount of GHG savings, that's the last column on the right-hand side. You need to put this in perspective because we only added 2,600 megawatts, and if you put it in perspective and look at AB 32, they were talking about adding 4,000 megawatts and getting 6.7 million metric tons savings of CO_2, so if you do that ratio and you look at the small print down there, which is why I do that, I add up each of the little boxes on the -4.3 is the increase in fuel, and the other four components are the savings, we got for Scenario 1 3.1 million metric tons savings. So what is Scenario 1? Well, I found out what Scenario 1 today was, Scenario 1 is the AB 327 assumption, basically saying that if you put in CHP, there's either not enough time, or utilities have signed up enough contracts that they're not going to pull out any new renewable resources. So the assumption was you put in the extra CHP and that reduces the demand by a certain amount, so the 33 percent RPS really would turn into a 34.6 percent RPS, so that's the percent of the load or total energy that the renewables would meet; instead of 33 percent, it bumped up to 34.6 percent.

The second scenario would be the ICF critique, and that's where for every megawatt of CHP that you put in that reduces demand, that's not exported, you would be reducing the amount of RPS, the amount of renewables that are put into the system.

MR. HARVILLE: I have to ask you to wrap it up quickly, please.

MR. ROCHLIN: I'm wrapped.

MR. HARVILLE: Thank you.

MR. ROCHLIN: Wait, wait, one second.
MR. HARVILLE: Please, go ahead.
MR. ROCHLIN: And so what that shows you, that Scenario 1 represented about 69 percent CO_2 savings and Scenario 1 would be a 31 percent, and my assumption is that we probably lean more towards Scenario 1 than Scenario 2, and go to the last slide, and the last slide, the conclusion really is the third bullet: the analysis shows that the emissions reduction capability of CHP, while reduced, is still substantial and should not be dismissed. Okay, thank you.
MR. HARVILLE: Great, thank you, and sorry to have to rush you along, but I appreciate you closing up quick there for us.
All right, at this point, I'm going to open the floor for questions, but I just want to clarify, I understand there's plenty of assumptions and methods in here to have plenty of room for discussion and debate, and we're having a whole panel, that's our third panel is going to be on this topic. So for now, if you have questions that are discussing or debating the assumptions of these different papers, if you could just hold off on those, and if could only

have any questions that are just clarifying or methodological? Do we have any clarifying questions for any of the authors? Okay, great. Then we'll move right along.

I think you all know me, I think I'm the next one on here, aren't I? I'm Jason Harville, nice to meet you. So I will make this really quick just to see if I can save us a little bit of time here. Sonika, you might recognize this table I borrowed pretty liberally from you, and just made a couple of small changes, I'm sorry for the small font there.

Essentially we just wanted to briefly go over for anyone who wasn't familiar with what we're leading into here with the third panel is that there are, as she rightly pointed out, a variety of different standards and metrics for evaluating CHP. And so here is a table that she has in her paper that essentially kind of runs you through them, and just to make it quick, you can see there are sort of two types, there's an overall total efficiency, which you can see PURPA and AB 1613, the first two rows in that table. I have the equation up there, but really the point and the difference here is it's asking how you value that thermal resource. And the main difference between these two is PURPA chose to discount the value of that thermal energy by half, whereas in AB 1613 we didn’t. But otherwise both of them are a total efficiency metric. And then sort of on the other side of how maybe you might measure the CHP resources, is the double benchmark which Sonika advocates and they use in their paper all the graphs with the lines and showing which side of it you’re on, these are the double benchmarks, and these really boil down to two key assumptions, and it’s the assumptions of what you’re displacing. And because it’s a double benchmark, you’re displacing a thermal generator and electric. And so really I guess when you get down to the nitty gritty of the difference between these programs is they’re different assumptions: What is the thermal resource that’s being displaced? What’s the efficiency of that boiler, or water heater, or whatever it is that you’re using to meet your thermal load? And then, on the other side, the even trickier part of it, is what is that marginal -- or maybe not even marginal -- what is the avoided grid emission? What’s the grid heat rate that is being displaced by generating with a CHP Unit? And so this is really the meat of these two things, this is what hopefully we're going to get into and talk about, and I'm going to leave it at that so we can move along.

So up next we have a presentation on Boiler Efficiencies. The presenter is going to be Dale Fontanez from SoCal Gas. Dale is a Project Manager in the SGIP Program for SoCal Gas. He's been an RD&D Project Manager, a Regional Account Executive, a Technical Account Executive for Cogeneration, and a Test Engineer in his career at SoCal Gas. Dale is a Certified Energy Manager with a BS in Mechanical Energy, and an MS in Engineering Management. Thanks, Dale.

MR. FONTANEZ: For the sake of time, you know, we could push through some of the early slides because we really just go into basically what a boiler is, how they're used, I mean, that's your basic boiler. You can go to the next one. These are boiler terminologies, some boilers are used for low pressure, high pressure applications, hot water, steam, and the like. Go ahead to the next slide, please. These are your most common types of boilers that you find, whether they be commercial or industrial application, but Water Tube and Fire Tube Boilers are the most common. They're all capable of achieving similar efficiencies and similar applications, there are a lot of different reasons why you might choose one over the other, but essentially this is what the boiler fleet is primarily comprised of. Next slide, please.

These are kind of all the different types of applications, markets they serve, again, we'll go to the next slide. Boiler efficiency. The most common way to measure boiler efficiency is what we call combustion efficiency, and essentially this is the energy that's coming out of the stack of the boiler. A boiler technician would use a probe to put in the exhaust stack to determine how much energy is there, and by that establish the boiler's efficiency. They do that to tune the boiler, so they know when it's doing bad, when it's doing well, and they start tuning it until they get to the best combustion efficiency that they could achieve.

Thermal efficiency would be kind of the next step where you are basically doing the combustion efficiency, but now you’re taking into consideration the losses of heat through the skin of the boiler and blow down processes, right? And then the last term, and this is a term that’s used mostly by the energy efficiency programs, is the annual fuel utilization efficiency. And this is an attempt to incorporate seasonal uses, fluctuations of load and the boiler usage is kind of a transient efficiency number. Next slide, please.

So these are the different things that affect the efficiency of a boiler. The burners, there’s a plethora of types mostly in California, you don’t see Atmospheric burners anymore, but to even get to a point where you’re going to achieve like an 80 percent efficiency, you need a power burner, and they come in different types, different ranges, high efficiency low NO_x, some have flue gas heat recovery, then there’s 0_2 Trim, if you look at any type of energy efficiency suggestions for boilers, it’s all about the oxygen, the percent of combustion and what you see in the exhaust. Another way of improving efficiency is putting a variable frequency drive on a combustion air fan, and then also stack economizers, which basically pre-heat the boiler feed water, they're efficiencies or the efficiency improvement of a boiler will vary based on your application, right? The temperature of the return water to the boiler. And then there's flue gas condensers which really go to condensing economizers. We don't see a lot of those in the state, but something you should be aware of. Next slide, please.

So this chart basically is data that was drawn from the CEC's database on boiler manufacturers data, there is specifications for boilers that they sell in California. And then it's broken down in this chart both for hot water applications and steam boiler applications because I wanted to give you a representation of what the energy efficiency programs, state funded energy efficiency programs, the efficiency levels that are required to get an incentive or rebate for the efficiency of your boiler. So pretty much from left to right, you go from small to large for hot water boilers on the left, and steam boilers on the right. And you'll note for hot water boilers you get to 85 percent efficiency for the larger things, you can get a rebate or incentive. For steam boilers, we start at 82 percent, kind of max out at 83 percent, and then you can get an incentive or rebate for the efficiency of those boilers. And then right up, we'll go to the next slide, there's four slides like this one, this is for the smaller hot water boilers, but each one of those black lines as a rise represent a specific boiler from a manufacturer and its efficiency when you purchase it. And you'll note as you move to the right, there are a lot fewer that achieve over 85 percent than those that achieve less than that. And we can go to the next slide, it's basically the same thing for a larger hot water boiler, the next one same thing for small steam boiler, and then the next one, and you'll see for the larger steam boilers it's still the same, most of them pretty well start at 80 percent and it takes some doing to get up to the higher efficiency numbers. And then I think the next one is my last slide.

So to conclude, it's basically what I've said, most existing boilers in California don't achieve 85 percent without some kind of help, especially steam boilers, 83 to 85 percent are the efficiency standards for energy efficiency to qualify for rebates and incentives, and to achieve 85 percent for most cases, especially steam boilers, you have to add something, the OC trim, the VFT, and economizer, and those things come at a cost. So to achieve those efficiencies, you know, you're going to pay premium dollars for it and I think we all know how fickle industrial customers, especially, are. That can be daunting at times. And that's it. Thank you.

MR. BLUESTEIN: Can I just ask a clarification question?

MR. HARVILLE: Sure.

MR. BLUESTEIN: When you were saying Mbtu, is that 1,000 BTUs?

MR. FONTANEZ: Yes. So you're starting right around your 2 million BTU boilers.

MR. BLUESTEIN: Okay, so relatively small by industrial standards?

MR. FONTANEZ: Right. So that would be something you would see, say, in a small metal finisher's plant, right, for hot water.

MR. HARVILLE: All right, great. Thank you. Oh yes, please.

MR. CONSIE: Yeah, this is Dan Consie

with CAMS. Just to point something out that's pretty basic to the presentation on boiler efficiency is the difference between LHB and HHV and natural gas. And when we're talking about boiler manufacturers, in particular if they advertise an 85 percent efficiency, that's usually in almost all cases at LHV. So when you combust natural gas, 11 percent of the energy goes into one of the products of combustion, which is water vapor, specifically the latent heat of vaporization of that water vapor in the gas itself. So unless you're actually -- and Dale made an allusion to it -- the condensing economizer, is one of those areas you can actually get some of that energy back. But the long and short of it is, unless you've recaptured that water out of the flue gas, you do not recapture that 11 percent energy. Thank you.

MR. HARVILLE: Great, thank you for that clarification.

MR. FONTANEZ: Just to kind of back that up, I mean, basically thermodynamically unless you can get through the latent heat region and actually recover some of the water from the air, you really can't get over 87 percent, it's not possible. So that kind of goes to the application of the boiler, so in some cases you can, in most cases you can’t.

MR. HARVILLE: All right, thank you. Okay, for our last paper presentation here, we have a slightly longer presentation of a proposed methodology for estimating fuel displacement for California electricity reductions by Bryan Neff here, my co-worker. Bryan has worked on Combined Heat and Power issues for the Electricity Analysis Office for over four years. He oversaw the ICF Consultant Report from 2011. He authored the Energy Commission Staff Report, “A New Generation of Combined Heat and Power: Policy Planning for 2030” that was referenced a couple times earlier. His latest work is a forthcoming staff paper, the one I just mentioned, “Estimating Fuel Displacement for California Electricity Reductions.” Bryan has a BS in Physics from Cal Poly and his MBA from U.C. Davis. Bryan.

MR. NEFF: Good afternoon, everybody. I’m Bryan Neff. And this presentation covers the core information that’s going to be in the forthcoming staff paper. A summary of the paper is online and the presentation was made available outside. So with that, there’s a lot of information to cover, so I’m going to get started.

Today I’m going to cover the purpose, walk through the scope and the limits of this presentation, characterizing the grid resources, covering the data source that will be using the assumptions that go along with using that data source, estimating grid heat rates, and how to project that into the future, and then run through an example.

So the purpose of this staff paper is to propose a common method for estimating the amount of fuel displaced from avoided use of grid electricity. For this method to be a common basis for comparing programs, it needs to use a common set of assumptions, being neutral to current policy and future state policies, and relying on a similar set of resources being displaced. To do this, it relies on historic heat rates for generation and the trends found within those heat rates. And finally, this proposal is meant to be a starting point for the discussion to elicit input, and there are several questions at the end in the conclusion of the summary paper with which I'm requesting written comments on.

So the scope of the method uses a simple tractable approach to estimating GHG reductions, and it does this by calculating the amount of fuel not consumed. And this requires using grid heat rates. Some of the initial questions faced in this process were what are the resource categories that we were going to use, how we were going to average them, and what geographical boundaries we were going to use. And so to do this we looked at peaking resources and what I've called load following resources, it uses an annual average and it's a single statewide projection.

Now, this method takes a fairly narrow approach when it's looking at the grid. It does not touch on the energy or the emissions that it takes to reduce grid use for CHP, since that's the topic today, it does not touch on the fuel that the CHP Unit will use, nor the displaced boiler fuel. Since this method uses an annual average, it's inappropriate for using it for short term estimation on day-to-day operational changes, or on seasonal variation. It also relies on numerous simplifying assumptions and the validity of those assumptions. So if those assumptions change, the method may not hold.

So in characterizing the grid resources, we're trying to define what is the marginal resource. Base load resources are those that are bound by technological constraints and are not used to match the supply demand balance on a daily basis, they're not ramping. Those include nuclear, geothermal, and coal. Other resources that are non-dispatchable provide energy according to their own schedules such as renewable generation with variable sources of power such as wind and solar, as well as Combined Heat and Power. So these are not dispatchable and they're not used to meet that balance, as well.

Two more need to be talked about, one is hydroelectric power, and this is tied to a myriad of physical, environmental, and societal constraints because of its multi-purpose nature. It's no longer sufficient to provide peak critical power to California because its demand has greatly surpassed the capacity that hydropower can provide. It helps shape loads, but is no longer considered to be on the margin because of its price. So this leaves natural gas resources. But before I get into the instate natural gas resources, I want to first touch on imported natural gas.

So some of the data that's available to the Energy Commission about out-of-state natural gas resources doesn't let us define how much energy from which of those resources meets California's load and at what times. However, we do have information about what the operating characteristics of those plants look like, and most of those natural gas plants are similar to California's modern fleet, they were built after 2006 and have similar heat rate curves as California's modern gas fleet. So it can be assumed based on these characteristics and the similarity of these heat rate curves that these plants, if they're used in a similar fashion and dispatched in a similar fashion to California's natural gas plants, that they do not significantly alter the average heat rates of the instate gas plants.

So now we turn to instate resources. And to look at those, we utilize the QFER Database. The QFER Database is imported data on fuel use and electricity generation, reported by the generators. We can use these to come up with the heat rates. Again, these are aggregated on an annual basis and are in a single statewide group.

However, this differs from another report our office does covering all natural gas resources because a number of natural gas resources have to be removed from this analysis because of their specific role they play in maintaining system stability. These would not be displaced with putting renewables on the system or something like that, they have to run.

So now we look at the historic heat rates that we're able to get from QFER. QFER was created in 2001, so these are the heat rate curves from 2001 to 2013. We define the peaking resources as having a capacity factor of less than 10 percent, and the load following resources are the remaining resources. Most of those are Combined Cycle Combustion Turbines, but not completely.

So as you can see, there's a trend here, and to get this and estimate a projection of the future, I applied a simple linear regression to these, taking in mind that during the electricity crisis in 2001, resources were not being used atypically. So the years 2001 through 2003 were removed from this analysis because of that development that occurred in that year and the subsequent years.

So this yields a projection going forward into the future; however, there becomes an issue in the year 2023. The heat rate estimates exceed that of currently available technology as analyzed by the Energy Commission Cost of Generation Report.

So staff proposes using the low estimate from this Cost of Generation Report, the Conventional Combustion Turbine low estimate for peaking resources in 2023 and beyond, and the low estimate for Conventional Combined Cycles for 2023 and beyond. We compared these numbers and show the low estimate because they most closely align with those technologies that were installed and reported in QFER in 2012 and 2013.

The one last thing we need to do before we can apply these estimates are to account for line losses and I think many people have touched on that already. Since there's no pre-public or publicly pre-vetted value, I've chosen to use a value of 7.8 percent. The 7.8 percent is a value that was used by the ARB in its Scoping Plan, and they derive that value using the California Energy Demand Forecast from 2008 to 2018. And that was a forecasted line loss value, a single statewide value, so it seemed very applicable to use it here.

So putting this altogether gives us the applicable heat rate estimates. So these curves illustrate the heat rates that will be used. In the Appendix there's an actual table of these heat rates. So the top curve would be the peaking resource heat rate for the onsite equivalent, the second one being the peaking resource for grid, and then you have the bottom two, a similar fashion, the load following heat rates for onsite equivalent, and the load following resource grid heat rates, and as you see in 2023, we apply the heat rate floor.

So before I get into applying these into the examples, we have one more thing which needs to be discussed, which is limiting the amount of displaced energy you can get from peaking resources. And so this is a graph of the percentage of energy from those peaking resources over the total energy from these dispatchable resources, and so as I talked about, they're defined as having a capacity factor of less than 10 percent, however, you see that there's great variation in the amount of energy actually used from them. The early years is also because of the electricity crisis and that peaking resources were not used as peaking resources, they were used much more broadly. The later years, the variation is caused by the amount of hydropower in the state, and also the severity of the summer's heat. So to analyze this and get a single value, I removed 2001 and 2002 because of the atypical operation, so the remaining values took out the high and the low and averaged them. And that yielded 2.5 percent.

So now I'm going to walk through how to apply these estimates to get a displaced electric grid fuel equivalent and it's a fairly straightforward procedure. You take the amount of energy that would be displaced on peak, and you apply the applicable peak heat rate, whether it's onsite equivalent or the grid rate, and do the same for the load following energy, multiply that by the applicable heat rate for onsite, or the grid heat rate. Again, the peak energy is limited to 2.5 percent annually. And then we can convert this to greenhouse gas emission reductions by applying a carbon content conversion factor. The 117 pounds per million BTUs is the factor the U.S. EPA uses, and that is I believe the same factor, but in metric tons for what the ARB uses in its Scoping Plan.

So I’m going to run through one quick example that uses CHP. So here’s the number of assumptions for this example, it’s a five megawatt facility assuming an 80 percent capacity factor, and that 20 percent down time occurs in off peak hours. So the total possible energy for the year is just under 44,000 megawatt hours. We apply 2.5 percent of that to get just over 1,000 megawatt hours for on-peak energy avoided, and just under 34,000 megawatt hours for off-peak avoided.

I’m going to make one more assumption going into this example and that is assuming that half of this is used onsite and half of this is exported to the Grid, and this is to illustrate the different heat rates. So as you see, this is a 50/50 power split between onsite and export, and so I start with half of that 1,095 megawatt hours, so you get about 550 roughly megawatt hours times the onsite equivalent peaking heat rate, and then you add that to the half of the load following value plus the load following onsite equivalent heat rate, and then you repeat that, but using the grid values, the 10-4-76 BTUs per kilowatt hour, and the 7-3-30. So crunching the numbers you get about 271 billion BTUs of avoided fuel. Applying the carbon content conversion factor yields about 31.7 million pounds of CO_2 avoided.

So this table, I have a number of other examples and in light of time they're in the back, and this is just a summary of that, so I'll just run through the summary and what they are quickly. The All Onsite would be all the energy used onsite, the All Export is the exact opposite, all the energy that would be exported to the grid. The 50/50 mix is the example we just ran through, and the 50/50 mix without the peaking energy is having that 20 percent down time include the peak, so there is no energy produced on peak.

And so with this, you'll see you get different displaced carbon intensities, and this carbon intensity is just the amount of CO_2 over the amount of megawatt hours. And so you can see the difference between the Onsite and Export shows the effect that line losses have on the displaced carbon intensity, and you can see the difference between the peaking energy, the 50/50 mix examples, the effect that peaking resources have on the carbon intensity.

So in conclusion, this method attempts to provide a common approach instead of assumptions to estimating fuel displacement from avoided grid use of electricity. As I said earlier, it does not touch on the energy or emissions it takes to reduce grid use. This method may be used to estimate reductions over the life of a program because it provides a 15-year projection, but conversely it cannot provide time sensitive estimates since it does not have the granularity needed to deal with daily or seasonal variation. It presents a standardized way to compare relative benefit of grid reduction measures, but is not a substitute for actual measuring of reductions. As you saw in the previous chart, there is no single displacement value and this variation is driven by the ratio of peak to non-peak power, as well as the line loss factor, the increased benefit of onsite reductions.

And finally, this proposed method relies on numerous simplifying assumptions, pertinent changes to the assumptions may require substantial changes to the method in order to maintain its validity, however, as long as the assumptions hold, the heat rate estimates may be easily updated using the QFER database.

So finally, thank you and I encourage those participants here to write written comments addressing the questions in the summary of this summary paper. Thank you.

MR. HARVILLE: All right, Bryan. We're going to ask you to sit on any questions you may have for just a little bit longer. Okay.

MR. HOFFMAN: Bob Hoffman with Occi. Bryan, thanks -- great presentation. A couple of things on your slide 10, you have conventional combined cycle and conventional with duct firing, you have the same heat rates, and I would encourage you for the duct firing portion to look at the incremental heat rate of duct firing which can be significantly higher, just a thought.

MR. NEFF: I will take a look at that. This came from the draft report, and that is currently going through some revisions.

MR. HOFFMAN: Sure.

MR. BARKER: On the other hand, you'd use the duct firing during peak periods, so you would be kind of double counting if you did that.

MR. HOFFMAN: Well, it depends when you rack it up, it's not a conventional peak, I'm just looking at his chart, just to make sure things are accounted for. The other is with the advent of flexible capacity that we're watching through other venues, a lot of these Combined Cycle in conventional plants are going to be at part load, so I encourage you to look at part load heat rates and associated greenhouse gas emissions when those units are turned down and significantly higher heat rates that take care of intermittent resources, lower efficiency, higher heat rate.

MR. NEFF: I think that's an interesting factor to include, and in this analysis, because it does use actual generation, the fuel and electricity generator from that, if we see that trend coming out as the years advance, that should show up in the data and it should show up in these heat rates.

MR. HOFFMAN: Yeah, the data kind of watches the annualized averages, but if you look at how the grid is dispatched day to day and hour to hour, you'll see a lot of noise. The other is the market also reacts on how the system is dispatched, and this doesn't just follow production cost modeling that other people have discussed.

MR. NEFF: Yes.

MR. HOFFMAN: And that's it. Thank you. Sorry to bother you.

MR. HARVILLE: Okay, thank you. If there are any other further questions, I hope they will be answered in the upcoming panel and, if not, we will have time for final questions and summary comments after this next panel.

So I'd like to introduce Ivin Rhyne. Out of all these nice bios I put together, it seems my manager was the one I forgot, so we'll see how that works out for me. But I'll tell you he's the Manager of the Electricity Analysis Office here at the Energy Commission. And he's been here longer than I, and he's an all-around good guy. So I'll let him fill you in on the details.

MR. RHYNE: So with that, that sort of glowing introduction, again, my name is Ivin Rhyne, and thank you, Jason, this is actually going to be I think probably the most fun panel of the day, not just because I'm operating it, but because it's actually pretty rare to get this late into the day and still have a packed house at a workshop like this. And as the presentations have gone on and developed over the course of the afternoon, we've really seen some themes develop here and we've got a really, I think, well-stocked panel here.

And just to lay out a couple of guidelines as we go, I'd like to start by posing a couple of questions, easy questions, I'll put them in air quotes, "easy questions," and really I want to encourage discussion around the table. I'm not going to be out to time anyone, but if I start to see someone start to monopolize time, I might reach out, you know, just ask you to pause and give your other panelists an opportunity to talk.

This panel is really focused on talking about the displaced emissions associated with CHP. CHP as a matter of policy plays an important role in California's grid, and in the future it's something that the Governor has certainly identified as something he wants to see developed, but he wants to see it developed certainly in a way that creates a net greenhouse gas benefit.

And one of the things that really comes out if you've been paying attention in the last few presentations is that determining what that net benefit is really matters as to what you're comparing it to. So in relation to what? In comparison to what?

And we know from Jason's presentation, very short presentation, that there are a couple of ways that that has attempted to be answered in the past. We have single efficiency standards that combine both the thermal and electrical efficiency and simply say a CHP unit achieving this efficiency is reaching a net benefit; and then there are the double benchmarks, the two efficiency pieces approach. And we've seen some discussions back and forth today.

I want to start by asking the panelists, and just for this first question I’m just going to ask to go around, and if you could just quickly summarize in your opinion whether or not it’s more effective and more efficient not only to accurately capture the greenhouse gas benefits of CHP by using a single benchmark, but perhaps whether or not it would also be beneficial to the CHP market, whether or not they should be trying to meet a single or double benchmark standard. And so I’ll start with the panelists here and if can just circle around. Thank you.

MS. SLOAN: Good afternoon, my name is Katie Sloan, I’m with Southern California Edison. I don’t believe I’ve been introduced today, so I just wanted to say hello so you know who I am and where I’m coming from. To answer your question, we like he double benchmark standard. I will say that we appreciate the work that Bryan has done and being able to look at CHP not just on its own, but in comparison to other resources that also reduce GHG. And we think going forward as far as a policy matter, we should be looking at CHP in that context. So that’s a quick response for you.

MR. RHYNE: Thank you.

MR. BARKER: Dave Barker, San Diego Gas and Electric. We support the double benchmark approach, but it should be based upon marginal stand-alone emissions that are looking forward, long term marginal greenhouse gas savings that reflect what's happened with all the other policies that the state has had, and then possible improvements in the thermal efficiency.

MR. RHYNE: Thank you.

MS. VAUGHAN: I'm going to agree with the double benchmark with my utility friends here. We had a great debate about this factor in the settlement days, those 500 days of meetings, and this was a very relevant issue, AB 1613 had been passed with a 60 percent efficiency, and then there was a debate going on here at the Energy Commission about the 62 percent, I guess, is where they ended up for AB 1613, so there's a lot of history there and I think it is beneficial to look at the double benchmark. However, I would actually agree with Katie that it is interesting, I want to commend everyone who has been doing these studies, I think there's a lot of information that's come out, and I think if anything it also raises the question of assumptions. And maybe that's what we need to drill down, and I think the PG&E report, the ICF report, Cliff's study there, as well, and also Bryan's, they're all based on assumptions and what I heard was we need more data, particularly some of the large CHP facilities. And I think that will help us as we go forward looking at what the performance data should be.

MR. DAVIDSON: I'm not sure I understand what a single benchmark is in this context, but I think to get -- if your benchmark is going to be in pounds per megawatt hour, or tons per megawatt hour, I think you've got to go with the double benchmark standard because electric efficiency and thermal both need to be factored in.

MR. RHYNE: Thank you.

MR. BLUESTEIN: Yeah, I think I have to disagree with the question a little bit because I think they're two different things. So I think what you were referring to as the single benchmark is an efficiency measure, and in that chart, you know, you have the PURPA is you're discounting the thermal by 50 percent, but then you're comparing to a standard of 42 percent, and then on California you’re not discounting it, but you’re comparing it to a higher standard, so it’s kind of apples and oranges just on an efficiency standard. And then the double benchmark is really more of an emissions comparison. So I think if you’re going to do an emissions comparison and you start out saying we really want to know how much is displaced, we’re really going to tons ultimately which I agree with. So if you’re going to go to tons, then yes, I agree you have to look at both if you want to call it the double benchmark, but you have to know what you’re displacing from the power side and what you’re displacing from the thermal side. So with that, caveat, I would agree.

MR. WILLIAMS: I agree with Dave and with Beth. I just love saying that because it doesn’t happen very often. So I would say from a policy application, yes, for topping cycle, natural gas-fired CHP, again, I think in terms of looking at bottoming cycle CHP, or renewable CHP, or some of the contracts that have come out of the RFO, which is essentially a hybrid of an agreement and a topping cycle CHP, then I think you need to look at the formulations that are a variation or a little different than the double benchmark. So I'll stop there, there's lots more to say, but I'll stop there.

MS. CHOUDHARY: I think I agree with everyone, there is nothing much left to say, but, yeah, looking forward and double benchmark standards do measure the performance of conventional gas-fired CHP and as we mentioned for bottoming cycle out of renewable site CHP they don't fall into the same category of performance evaluation.

MR. RHYNE: Thank you.

MR. ALCANTAR: I'm going to agree to an extent with Ray, which is really hard for me, but let's think about two things, one is the simplicity of having established double benchmark that's agreed upon and is at least identifiable and workable against, provides a signal to the marketplace, certainly CHP provider of what they need to do, and that clarity is important in its simplicity, and important and critical in terms of promoting the resource. I certainly can't say that I appreciate the work that Ray's group has done to draw a line that suggests that no CHP on his list is qualifying under that standard, which leads me to the second point: the problem is for evaluating CHP exclusively and solely on GHG emissions? I think we missed the boat. And that was the entire focus, I thought, of our earlier discussion today and needs to follow through. This is one component of a benefit of a highly beneficial type of generation.

MR. RHYNE: Thank you. Dale?

MR. FONTANEZ: I have a different take on it. I think the double standard is the standard set up to meet some kind of benefits you're going to get from a program, so every one of those double standards is related to either some kind of incentive, or some kind of discount. In order to look at it from an overall perspective, you should not be looking at it piecemeal, and I think each of these analyses that are piecemeal, you need to put it in a form of how is the overall system operating, and that's what I tried to do.

MR. WILLIAMS: I need one clarification. So, Michael, we did show that RPS adjusted line, but because we had seen it put into practice in California, that's different than PG&E recommending that that's what you should use.

MR. ALCANTAR: Right, and we can debate this all night long, but you sent out this report for some purpose. I impute a purpose to it. It has a conclusion, it wasn't friendly towards the constituents that I represent, I don't think, in terms of the conclusion you were trying to present.

MR. BARKER: But for SDG&E, I wouldn't back away from it at all, I think that's where we need to look at CHP in the context of long term where California is going in terms of emissions. If they want us to get to 500 and -- what was it, 74 pounds per megawatt hour? We should look at a utility portfolio and see is this CHP going to help or not help going forward.

MR. ALCANTAR: And, Dave, nobody in this room is disagreeing with making an assessment, call it piecemeal if you like, but I think there are a number of deficiencies in what's been presented, so we've identified those and we're looking at them today, and I think we're all trying to get to the same benefit, or at least identification of benefit with respect to GHG, just let's not throw out the baby with the bathwater, nor do we accept the set of parameters or assumptions that were made in the earlier assessment, in the first assessment -- the PG&E assessment.

MR. BARKER: I was just telling you that San Diego does accept that and does think that's the best way to look at it for the State of California.

MR. RHYNE: Okay, so let's take that and move I think to the next question, or one potential logical question, and the progression. In working with Bryan and putting his paper together, one of the more interesting pieces is just the diversity of estimates that are out there with regard to what is the marginal grid resource and what is the displacement from grid resources, and really he has worked hard to come up with some estimates of what that might be based on a number of assumptions. But what we see, not just in this area but in other areas, is that in terms of estimating an efficiency standard, or a greenhouse gas emissions standard, there has been historically some amount of a patchwork quilt approach, where for different programs, different standards are used, different staffs at different agencies, and this one is open to anyone on the panel who wants to comment. And I think I know the answer, but I want to make sure that we get this sort of on the record, as to whether or not we agree or disagree with the idea that each of these programs, whether they be applied to CHP or otherwise, should be coming up with their own approach to estimating what displacement is, or should everyone, meaning those who work in this policy field, be essentially drawing from the same set of assumptions so that everyone sort of is speaking apples to apples. Please.

MS. VAUGHAN: I’ll have a go at that and I think maybe it goes to what Cliff said, is it is piecemeal, and if you look at -- when I think of, well, 1) I don’t think we have a State CHP Program, all right, we do have individual programs like SGIP, like AB 1613, and the Settlement. And they all have different objectives, so if you go out with different objectives, you’re going to have different ways to measure your progress towards achieving those objectives. And so consequently, you know, speaking about the Settlement double benchmark, that was simply a negotiation, it’s again not good public policy, not based upon some kind of assessment of what are we truly displacing, and so I would take it back to some of the comments this morning, I've forgotten who it was that said we need some leadership in terms of somebody to say, okay, we're going to develop a State CHP Program, then I think you look at this displacement issue and maybe you can apply something like that across the board. And then to Michael's point, then as a developer going forward you've got a clear indication. At the moment, you're simply, you know, with the Settlement they're looking to achieve GHG emissions reductions based upon seriously a crazy accounting system that we have in Section 7, which should never be applied to anything. So that's kind of my assessment of it. The moment we have different standards for different reasons, and I see the logic behind each of those, but in terms of going forward, hand in hand I would have to go with a State CHP Program.

MR. WILLIAMS: Just a very short -- I would agree that we should not be importing the CHP QF Settlement methodology here, we were trying to address lots of contractual situations and retirements, and so forth, and don't think that's really a good place to start. I will call out one, though, and I think it's AB 1613 where essentially it's a flat line; in other words, the power to heat ratio just really doesn't factor into it. And what that means is that if you have a high power to heat ratio, you essentially have no chance of meeting that threshold, and if you have a very low power to heat ratio, and I think I got it right, then it's in effect too easy. So the one instance that I've seen where there should be really a redesign, the rest of them I think have to do with various assumptions around boiler efficiencies and marginal grid emissions rates where we've had a good discussion here. Joel did point out to me, that I hadn't realized, is that boiler efficiencies might be different for heating water than an industrial application, you know, that might be a reasonable distinction to make.

MR. BLUESTEIN: You know, there's a lot going on here related to CHP that I'm not very up to speed on, and there's some unique things about CHP that make this discussion more interesting, but you know, for other reasons we want to know what is displaced by energy efficiency, we want to know what is displaced by renewables, and I do think just from a broad policy perspective we shouldn't have 10 different answers to that question. And when you reduce a certain amount of megawatt hours of generation on the grid, I think we ought to agree that it has the same effect, whether it's energy efficiency or renewables, or CHP, from this system or that system, we ought to have some consistent methodology, so call me crazy. And I say that because I've had this discussion about NO_x emissions and every other possible thing that can happen on the grid, and I've seen many many different approaches to calculating it. And I think, you know, CHP brings in the added complication and benefit of the thermal side, but on the grid side alone, then there have been many attempts to do this, again, for energy efficiency, for renewables, for WRECs, for allowances, it's all kind of the same calculation. And I think, then, the question is how complicated do you want to make it. I agree that, you know, running a dispatch model is the more complete way to do it; that said, I don't think any of us have had a chance to really understand what you did, I'm sure it's perfect, but we all want to -- and so that would be probably the most rigorous, but would we be able to do that all the time? You know, Bryan's approach is maybe in between and then kind of a simpler version that some of us have done is, you know, the more expeditious. So I think there needs to be a decision about how much complication you can accommodate and then let's say that's what we're going to use across the board. And then the thermal piece, you know, isn't that complicated. The other thing I would say, though, is when we're doing it prospectively, it's a little more complicated than sometimes when we're doing it from a compliance perspective, right? So if I'm thinking about, you know, an imaginary CHP Unit, sometimes it's more complicated to estimate what the power to heat ratio is than when I'm actually looking retrospectively and I know exactly how much steam was produced, and how much fuel was consumed, and how much electricity was produced. Then it's very easy for me to know what the emissions were and what I displaced, at least how much I displaced. So just a few thoughts there.

MR. RHYNE: Thank you. Anymore comments on that question?

MR. DAVIDSON: I think the industry would really appreciate it if the state would come out with a consistent Guidebook, a consistent set of benchmarks that you have to meet that everybody knows is going to stay consistent, maybe not consistent in time, but consistent in methodology in time, and we all recognize, I think, that the marginal heat rate is probably going to keep going down with time, and the average efficiencies going up with time, and that's okay. But I think to have some kind of common projection for how things are likely to go in the future, and where things are today, and maybe it's also worthwhile to somehow, maybe not give an 8760 hour breakdown, but somehow give people a sense for if now and in the future if it's going to make -- if there's going to be some motivation for them to try and dispatch their facility during certain periods of the day or the month, but I think some consistent framework from the state would be welcome by most people.

MR. RHYNE: So I want to pause for a

moment, and I didn't do this at the end of the first question, I probably should have, and just sort of acknowledge that rare moment of unanimity around the table at that first question. I should probably mark my calendar and celebrate this on an annual basis. But what's interesting is the other thing that I'm hearing in broad strokes, and I just want to make sure that I'm hearing this correctly, is that there's also largely, although not everyone has commented, but largely a consensus that some state agency, whether that's the Energy Commission or someone else, no one has indicated, but should take the leadership role in terms of creating an approach that is sort of standardized to estimate this. There is certainly room for input and improvement, I think, as we go through what that approach looks like. But that we begin from a common understanding of how to estimate the greenhouse gas emission value for those sorts of programs that displace fuel and emissions from the Grid. Would anyone disagree with that statement? All right, so let it be noted that that was silence and not a skip in the tape.

So that actually brings us to the next

question and I think the SoCal Gas, that Dale's presentation was actually really well timed because one of the interesting things is that we tend to focus on electricity for those of us with an electricity background, and not on a thermal side, especially when it comes to CHP, especially when we talk about natural gas, and yet estimating what those reference values should be is an important element. So I'm going to open the question first on the natural gas side. I think we have numbers that look at 85 percent boiler efficiency, there's some estimates that include 80 percent boiler efficiency, and there were a couple of very interesting graphs that Dale showed about the actual filed efficiencies of some of the water heating and steam heating. What thoughts are there around the table as to what perhaps might be a good or better approach to estimating the steam side of efficiency, the boiler efficiency? What should we be drawing on and how might we approach it?

MR. BLUESTEIN: A couple thoughts. First of all, it hadn't occurred to me that some of those efficiency numbers might be LHV efficiencies because I guess my experience is usually boilers are expressed in HHV and turbines are in LHV, but if any of them were in LHV, then certainly that makes a difference. And the other thing is that there is condensing equipment, the equipment that condenses the vapor and gets like home hot air furnaces, you know, condensing furnaces are common in residential equipment -- no? Okay, well, they exist which is more than you can say in the larger sizes.

MR. FONTANEZ: That would be true. And I would say they're not so common just because they're expensive.

MR. BLUESTEIN: Yeah, well, and so let me just caveat, I live in the East Coast where people have higher heating bills, so the condensing furnace can pay off, but in Southern California? Probably not. So anyway, the point is they exist in the residential heating market and that's why I was asking about the size of those boilers, that those boilers you were talking about are still relatively small relative to what I would refer to as an industrial boiler that's, you know, 100 million or 150 million BTU that you find at a refinery or a food processing plant, and just the point there being that condensing boilers of that size range are not really common. So those higher efficiencies would be less common. But for a variety of reasons, I’ve been looking for the answer to this question for quite a while, like 20 years, and so I think we still haven’t quite gotten there yet.

MR. FONTANEZ: Well, just one caveat with that, too, you know, those people who own those really large boilers, they have a lot to gain by achieving a higher efficiency, so it could be that, you know, the majority of the really really big boilers are 85 percent because the fuel savings -- no, no -- the fuel savings is significant. I said “could be” because it’s just because of fuel savings.

MR. ALCANTAR: It would be, I would say, if they could achieve that it would be great, but I think to the extent that we have data, and another place to look is the Council of Industrial Boiler Owners, and they’re adamant that these -- and whenever this comes up they’re very vocal that, yeah, we’re not getting those efficiencies.

MR. FONTANEZ: One other thing with the data I put up and this is kind of consistent with what you're saying, once we get over a couple hundred horsepower with the boiler, whether it's 200 horsepower or 2,000 horsepower, you know, it's scalable. The efficiencies aren't going to improve or get higher because it's bigger, it's not like turbines. You know, bigger turbine wheel, higher efficiency; boilers don't work that way. So from I would say 100 horsepower to 10,000 horsepower, same types of burners, same types of things attached to the burner, or with a stack economizer, you're going to get the same kinds of efficiencies.

MS. VAUGHAN: And thank you, Joel, I've been looking for the last year and now I know that you've spent 20 years, so I'm going to stop. So that's my takeaway from today.

MR. BARKER: So for a slightly different perspective, though, is again, if it's the high heating value, is the 82 percent that we're giving energy efficiency credit for, whether we're giving money to get that, it seems like that ought to be a standard because we want to be looking forward and not looking backwards.

MS. VAUGHAN: But is that for the large industrial?

MR. BLUESTEIN: I mean, to some extent that might be true, but the reality is most of the boilers, which is what they're alluding to, don't make that 83 percent efficiency. That standard is based on you having spent money as a premium already, just to get to the 83 percent, right? Where the standard product that most people are going to buy don't achieve those efficiencies, so I'm just clarifying that that's probably not true.

MR. BARKER: What's not true, that you give 80? You give energy efficiency for 82 percent?

MR. FONTANEZ: Well, I don't know where you put the number, but it's not on the higher end. For the most part, the fleet is going to be less efficient.

MR. BARKER: Well, your charts show that you are giving incentives for reaching 85 percent, or 84 percent, or 82 percent, depending on the size and the --

MR. FONTANEZ: That's true, but I'm saying that's on the high end. If you saw the other charts with the available boilers on the market, it didn't achieve those numbers, the majority did not.

MR. BARKER: So you're giving incentives for something that doesn't exist? Is that what you're saying?

MR. FONTANEZ: No, you're giving incentives to achieve a number that you have to pay a premium to get to that efficiency. But most of the fleet does not achieve that, so if you're going to do an analysis on the market of what's really out there and what you're really displacing, you should use the real numbers, not what's possible.

MR. BARKER: Well, but if you're putting in something new and you're choosing between a new boiler or putting in CHP, wouldn't it be what's going forward is going to be the efficiency?

MR. FONTANEZ: I'm thinking a lot of customers are looking at doing CHP because they have an older boiler, and instead of making the investment just on a boiler, which is very expensive, they're going to do CHP to save on energy another way and extend the life of that old boiler.

MR. RHYNE: And I think we have a

question on the other side of the room here.

MS. CHOUDHARY: Just adding on to the discussion about the data part, so I saw from your graphs, like you were referring to the CEC Appliances Database, and --

MR. FONTANEZ: It was the boiler database.

MS. CHOUDHARY: Yeah, and I also refer to the same database and I was not able to see the segregation based on the application size, the other –

MR. FONTANEZ: You had to calculate it. Those charts were taken right out of the SoCal Gas’s White Paper for Energy Efficiency that established the standards for the incentives, which is a state program. So the data is there, you can get it.

MS. CHOUDHARY: So the overall, I think the message I’m getting from this panel discussion is we need more data, public data out there, both on the boiler efficiency side and also it should get more granular in terms of what’s the boiler application, is it the water heating or steam heating? And they have different standards of efficiency.

MR. FONTANEZ: Well, and that's maybe another point because part of what I think about because I've always done work with our customers that do a lot of small co-gen, is that it's not always displacing a steam boiler, it could be a hot water application, right? I mean, every application is site specific, that goes to their thermal loads and their electric loads, so what is optimal for one customer to run their CHP versus another is going to vary, and which goes to what a lot of the manufacturers were talking about, you know, the economics. The economics rule, right? So there's a better chance of CHP being cost-effective if you run it 24/7, but there may not be as much of a benefit running at night than there is during the peak hours. I mean, there's all of those considerations.

MS. SLOAN: And just one other general comment. I think what this is highlighting is that not all CHP is exactly the same and it does get very facility specific. So as we're talking about standards, we need to be looking at how the CHP facilities are being used, what they're being used for, and to the extent that we can have more public data, I think that would help, too, inform the --

MR. FONTANEZ: And maybe even the technology that is applied to particular industry, maybe.

MS. SLOAN: Right, so we're talking about CHP in general here, but there are very different uses of CHP.

MR. HARVILLE: I'm sorry, can I get you to come to the mic so that everyone who is online can hear your comment?

MR. CONSIE: Yeah, one of the follow-up points to LHV versus HHV, the fact is manufacturers like, just like you pointed out, Joel, on the turbine side, they want to put out their marketing material based on LHV because if you say I'm 85 percent efficient at LHV, what you're actually saying is I'm about 75 percent efficient on total energy, so it's very important, they like to put that forward, they like to get that out there. But one of the other big pieces that we're missing is when they rate their equipment, they're rating it at full load, all out utilization. That typically does not happen in a manufacturing situation where you have to very -- the load on those boilers is based on the production, on the production line and where it's running. So when you're thinking about displacing what's actually out there, you have to take that into consideration as well. These boilers aren't simply sitting there base loaded. They have to follow the production.

MR. ALCANTAR: I want to follow-up on that and on Katie's comment. All of these applications are different. What we're struggling with is that, in taking into consideration the different heating values, and the size of the facilities we're looking at, and I appreciate the analysis done here, but these are tinker toys as compared to what we're talking about in terms of our applications. These boilers, you know, we're not talking about taking showers. So when you're running a refinery and looking at the type of size of equipment and experience with equipment, there's nobody who is experiencing the imaginary numbers that are being suggested here that you'd use. They're imaginary. So that's why you're getting the pushback on these. The data we can look at, but it's as much as saying, well, if I happen to go to my good SoCal provider and I'm looking at my domestic hot water, I can find a 95 percent efficiency hot water heater. Well, let's apply that to a refinery. No. That's the problem we're having today.

MR. RHYNE: In the interest of time, I'm going to move to the next half of this question, which I think more people might be familiar with. This has actually been really really useful, but I want to make sure that we continue the discussion along. And that's really to talk about the electric side. This is, I think, a big portion of what Bryan has been working on, and certainly when his paper hits the streets we'll really want to encourage everyone to read it carefully, critically, and think about it. But it's an interesting question, in general, but one that has very practical applications for when we get into valuing, at least on a greenhouse gas basis, anything that displaces emissions from the Grid, CHP being one of those things, and CHP has the interesting sort of behavior of in many cases being able to export, and in other cases, you know, staying behind the meter and sort of working there onsite. So it has many faces. And when we attempt to value it, one of the things that Bryan really worked hard on was how you make sure that you've accounted for emissions associated with grid operations, both on peak and off peak, and that takes into account transmission losses if you happen to be exporting, and taking account for the lack of transmission losses if you're just valuing the onsite value.

What thoughts do the panelists have on the best approaches to estimating what that grid emission value should be on the margin, and how it might be best used not just in any single study, but on an ongoing basis, in other words, built in such a way that it can be updated and improved over the years?

MR. WILLIAMS: Maybe I'll take a first shot at that. First of all, I really appreciate the presentation, I think it's a reasonable framework, it's public, it's transparent, and Bryan was, I think, very careful to talk about what it can be used for and not. So I thought it was a really good presentation. And we'll go through it and have certainly more comments later.

One issue that I would like to bring up

over the longer term is kind of a state aspiration to use expanded renewables plus storage, in essence to help manage the grid that's just to deal with that over-gen situation, and I think in the year 2020, which is our focus here, we kind of didn't worry about it, but as you get to 2030 and beyond, I think we do need to think about that issue and that's where the floor that you mention comes into play. And, you know, rejecting renewables, or using storage for renewables, you have to think about whether fossil fuel is on the margin when you're in that condition.

MR. BLUESTEIN: Yeah, I appreciate Bryan's work. Just starting from the point of defining, you know, the different pieces, this is base load, this is not marginal, so getting it down to what we're going to call on the margin, which is very important, there's a lot of variability in that, and then having transparent basis for getting the information from the QFER and so on, I think that's very helpful. But I think there were some other good suggestions that were made going forward about the way that the grid operations are going to change, in particular as the RPS ramps up and what will those load following units -- will they be unloaded combined cycle units? And how does that change their heat rate? So I think the methodology has a lot to recommend it and I think some improvements on the actual values, but just having it well-defined and based on transparent data is a big step forward.

MR. RHYNE: So that actually gets us to, I think, what I have listed here as the last question, but really sort of a more narrow question, and it’s been sort of mentioned in a couple of the papers. And it’s this concept that having an efficiency measure like CHP that reduces the net demand, therefore reducing the need to procure more renewables in order to meet the 33 percent goal, would therefore somehow reduce the change, the marginal emissions. Can I get some thoughts from the panelists as to whether or not changing the stock of renewables or changing the rate at which that stock is added, will or will not actually have an effect on what that marginal resource is likely to be?

MR. BARKER: Yeah, I’ve got to say, with the RPS penalty I’m just -- I just can’t get my head around the rationale for it. I understand the math, but to me it really flies in the face of a lot of other California policy, I think. I would come back to that. But I want to thank Tom Beach for mentioning AB 237, I didn’t see that -- AB 327, I’m sorry -- I didn’t see that clause in the legislation, and thanks for being Agnostic on this issue, I appreciate it. But, I mean, if you take a CHP system and you say it’s worth 33 percent less if it’s on this side of the meter versus two feet over on this side of the meter, to me something is wrong, and maybe it’s just the way that the RPS is defined on a percentage basis of wholesale power, but I really think the end goal is 2050, which is a fixed number, you know, it’s 80 percent of 1990 level, it’s a fixed number, and you’ve got a whole bunch of tranches and program initiatives that are going to get you to that point, and to me it’s almost silliness to say that, in the case of CHP, wholesale CHP has a better greenhouse gas footprint than CHP on the retail side of the meter. And I also, when I think about it, I say well, shouldn’t that same analogy apply to energy efficiency and that customer sided renewables on the customer side of the meter should be worth 33 percent less than renewables on the wholesale side of the meter and – are you going to interrupt me? Go ahead. No, go ahead, Dave.

MR. DAVIDSON: I was just going to point out that in the cost-effectiveness of energy efficiency they do assume 33 percent renewables.

MR. BARKER: They deduct 33 percent renewables, but –

MR. DAVIDSON: Actually it's I think 23 right now, but it's moving towards 33.

MR. BARKER: But they actually deduct the benefit by 33 percent?

MR. ERICKSON: Well, they add the cost of the renewable for the one-third that's replaced, or 25 percent that's replaced.

MR. BARKER: I just, I mean, you take the loading order, you take the Southern California Reliability Initiative with its emphasis on preferred local resources, and I don't know why you'd want to say that local resources on the customer side of the meter are somehow penalized versus stuff on a wholesale --

MR. RHYNE: And it looks like, I'm sorry, Ray, you've got a comment to make. I want to give you the opportunity.

MR. WILLIAMS: I'm Agnostic now from PG&E. That's where I am, but I take Keith's point to heart and that is sort of the economics being on one side of the meter versus the other, it's kind of a peculiar result of applying this policy and I think that's all I can say at this point.

MR. RHYNE: Please.

MR. BLUESTEIN: First of all, on behalf of ICF International, I respectfully decline credit for this putting forward that this is the way to address this policy. We did do some calculations that way in the CHP analysis, but I don't think we actually invented it, and it's not meant to be an advocacy position, so just putting that aside. But, you know, I think nobody has yet answered your question, which was how does it affect the marginal resource, and I think my sense is that it doesn't change the marginal resource. I think that it could change the effect on greenhouse gas emissions in the state, but that's a different question, right? And again, it's one of many cases here where we're trying to get at something, but we kind of go through different paths, you know. So we're trying to calculate a marginal resource so that we can estimate what the effect of displacement is at the State level, and that's an approximation. And then we're also thinking about, well, if it's over here, it might affect how the RPS gets implemented, and that has a different effect, and we could simulate that effect by changing our estimate of the marginal resource, but I don't think that's what actually happens in real life.

MR. RHYNE: Okay, go ahead.

MR. WILLIAMS: So setting the policy aside, you know, with load demand growth, electric demand growth, and a very high percentage of renewables, you may find yourself again into this over-gen condition, you know, as exemplified by the duck chart. And that's an actual sort of wholesale market operating condition. And, yeah, that's something that I think needs a more critical look and to see what exactly in that situation where natural gas is at its minimum and you're working with storage and non-carbon generation to somehow maintain reliability in a system, I think that's a complicated issue. I think that's where we need to take a look. But that's an actual condition, that's not a policy-driven outcome.

MR. RHYNE: Let me just follow that up, just to clarify. What I'm hearing you say is that you referenced the duck chart, which posits the idea that we may be in what you refer to as over-generation. In this situation, operationally, where an efficiency measure of any kind, CHP being one of them, creates the need to curtail renewables, that's over-generation – curtail, or spill, or somehow it begins to cut into the available renewable generation. That is a case in which you're essentially being penalized for the fact that you're now cutting back into the renewables generation. Is that -- would that be different than simply slowing the need to procure new renewables to add to the total stock of renewables in the state?

MR. WILLAMS: I'm not sure I quite understand your question. I'm just looking at the condition itself and not necessarily so much where the CHP (quote unquote) is causing it. If your question goes to -- and there is a person from the ISO who was here earlier -- if it does go to, you know, this mix of resources which is part dispatchable, part base load, and part intermittent, and we're looking at a lot of distributed generation on the customer side of the meter and relatively flat electric demand growth, all of those things together could put you in a situation where you may be in an over-gen condition for a significant number of hours, and I think that's just something we should all look at, and look at in a very sort of public and transparent way as we can.

MR. RHYNE: Thank you.

MR. ROCKLIN: I think that's what the production simulation model was trying to get at, that's why we picked 2021 because that was after the RPS meets 33 percent, and most, the vast majority of once-through cooling has been replaced. So that question is somewhat answered, it's between 33 and 69 percent, CHP still gave you that percent of the 6.7.

MR. BARKER: Of course, that assumes that CHP would export out of the state and reduce imports into the state from my understanding of your chart 5, was that it was all related to --

MR. ROCKLIN: Not all. There is a

reduction in overall California gas production and an overall reduction in coal outside the state, so California actually generated less gigawatt hours.

MS. CHOUDHARY: So Cliff?

MR. ROCKLIN: Yes.

MS. CHOUDHARY: Yeah, one of the comments for your paper was that it assumed the unspecified imported number, like the assumptions in your paper are not clear enough to draw that conclusion, that when we are going into that modeling and that deeper dive, so why not look at the resource-specific, like what is exactly getting displaced?

MR. ROCKLIN: It’s very hard to do in the Production Cost Simulation.

MS. CHOUDHARY: That’s like again a very broad thing that you are saying the 6,000 titrate CHP is displacing 8,000 titrate gas-fired emissions, that’s simplistic. Like after doing all the elaborate production simulation calculations, like those are the two critical --

MR. ROCKLIN: Well, that was the implicit heat rate that we calculated, so CHP was dispatched, and then other resources -- all the renewables were accepted, none of them were ever rejected, and so it was either gas or coal within the state, and without the state, that we got the benefit from.

MS. CHOUDHARY: You can do probably more in-depth analysis.

MR. RHYNE: Okay. With that, we've reached the end of the time allotted here for our panel. I really want to thank all the panelists for your participation. I want to thank everyone for taking the time today to sit down and share your views, and actually I really appreciate everyone being so concise and respectful to the other viewpoints around the table, and I really appreciate all of your input today. All this is on the record and we'll be sort of collating this. I think Bryan was scribbling furiously and we'll be working to take that, but I also want to get one last plug in before we do wrap this panel up, in that the staff paper which attempts to present a method for estimating displaced fuel emissions from a variety of programs, CHP being one of them, will be coming out shortly, and I really want to encourage everyone, not just the panelists, but everyone here in the room and those online who are interested in this topic, to read it carefully and to comment. I would really appreciate the feedback and we do better work, I think, when we have that kind of feedback and we're able to take multiple viewpoints into account. I don't think we can please everyone, that's sort of the nature of the business, but we certainly do, I think, come out with a better product. So I'm going to hand it back over to Jason.

MR. HARVILLE: Thanks, Ivin. I did make quite a few promises about accepting questions, I don't know if I made anybody wait this long, or hopefully your questions were answered, but if we have any questions or final summary comments from the audience, do we? No? That was a very thorough panel, answered all sorts of questions. Do we have any online? No. Okay, great.

Then I just have a few kind of closing points. It's not all necessarily bookkeeping, but I have information up there, this is just the basic information site. That's my contact information for any questions regarding the workshop or anything along those lines, you can please feel free to contact me through any of the methods up there.

Also, we have a new CHP website on the Energy Commission website, you can see the address up there. In the meetings and documents section, I have all the documents I've been able to upload, so far posted there, and I'm going to be posting the rest of them, along with the audio recording of the workshop, so you can go ahead and reference any materials you like there. If you are wanting to docket something, I have the docket information there also on the Notice that was published, the Public Notice, I think on page 3, 2 or 3, it's down kind of at the bottom. There's instructions for how to submit things to the docket. And if you have any questions on that, you can contact me directly.

Specifically, as far as the docket goes, I want to let you all know that we're going to be releasing some questions, it will go out on the Listserv, and if you're not on the Listserv you can do that right at our website there. But we're going to release a whole list of questions for written comment and I would just really encourage and ask you all to please look over these questions, see which ones pertain to you, which ones you think you have some input on that you'd like us to have, and we would really like to hear what you have to say about those. So that will hopefully be going out within the next few days, but the Listserv will be notified, and then we can take care of that. And once those questions are answered, I'm going to be writing a follow-up paper to Bryan's paper that we mentioned, it came out a couple years ago, whenever it was, but anyway that he did after the 2012 workshop, and just essentially updating that, coalescing, I'm going to try to bring together everything that was discussed today and put that out there. And those written responses will be really helpful for me in doing that. I know Ivin already plugged your paper coming out soon, right? And then that's the rest of it. Like I said, please contact me with any information, please sign-up for the Listserv, and give us any input you have on these questions. And I really appreciate you all coming out today. I hope you have a good day.

(Whereupon, at 4:31 p.m., the workshop was adjourned.)

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