STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

STAKEHOLDERS MEETING IN RE:

REVIEW OF ELECTRIC RATE ISSUES
IN ANTICIPATION OF 2015
RATE DESIGN REVIEW

DOCKET NO. 4545

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MAY 14, 2015
9:30 A.M.

89 JEFFERSON BOULEVARD
WARWICK, RHODE ISLAND

IN ATTENDANCE:

MARGARET E. CURRAN, CHAIRPERSON
HERBERT J. DeSIMONE, COMMISSIONER
CYNTHIA WILSON-FRIAS, LEGAL COUNSEL
AMY D'ALESSANDRO, LEGAL COUNSEL
TODD BIANCO, POLICY ASSOCIATE
ALAN NAULT, RATE ANALYST

FROM NATIONAL GRID:

CELIA O'BRIEN, ESQ.
PETER ZSCHOKKE
TIMOTHY ROUGHAN
TERRY BURNS
JEREMY NEWBERGER
JEANNE LLOYD
SCOTT McCABE

FROM THE DIVISION:

LEO WOLD, ESQ.
KAREN LYONS, ESQ.
AL CONTENTE
STEPHEN SCIALABBA

FROM ARCADIA CENTER:

MARK LeBEL, ESQ.
ABIGAIL ANTHONY
LESLIE MALONE

FROM NEW ENGLAND CLEAN ENERGY COUNCIL:

CHARITY PENNOCK
JANET BESSER
SUE ANDERBOIS

FROM OFFICE OF ENERGY RESOURCES:

DANIEL MUSHER
MARION GOLD

FROM CONSERVATION LAW FOUNDATION:

JERRY ELMER, ESQ.
MATT GREENE

FROM RENEWABLE ENERGY DESIGN:

SETH HANDY, ESQ.

(COMMENCED AT 9:41 A.M.)

THE CHAIRPERSON: I believe that we can get started in Docket 4545, review of electric rate issues in anticipation of 2015 rate design review. Is there anything we need to take up in advance?

MS. WILSON-FRIAS: I don't think so, Commissioner, other than maybe having everybody introduce themselves. Arcadia Center and New England Clean Energy Council and National Grid have each provided presentations which will be posted on the website after the meeting.

THE CHAIRPERSON: Shall we start identifying ourselves for the record?

MR. CONTENTE: Al Contente, Division of Public Utilities.

MS. LYONS: Karen Lyons for the Attorney General for the Division.

MR. SCIALABBA: Stephen Scialabba for the Division.

MS. GOLD: Marion Gold from the Office of Energy Resources.

MR. MUSHER: Dan Musher, Office of

Energy Resources.

MR. HANDY: Seth Handy, Handy Law.

MR. McCABE: Scott McCabe with National Grid.

MR. BURNS: Terry Burns, National Grid.

MS. LLOYD: Jeanne Lloyd, National Grid.

MR. ZSCHOKKE: Peter Zschokke, National Grid.

MR. ROUGHAN: Tim Roughan, the same company.

MS. O'BRIEN: Celia O'Brien, National Grid.

MR. NEWBERGER: Jeremy Newberger, National Grid.

MR. GREENE: I'm Matt Greene from the Conservation Law Foundation.

MR. ELMER: Jerry Elmer, Conservation Law Foundation.

MS. ANDERBOIS: Sue AnderBois from New England Clean Energy Council.

MS. BESSER: Janet Besser, New England Clean Energy Council.

MS. PENNOCK: Charity Pennock, New England Clean Energy Council.

MS. MALONE: Leslie Malone, Arcadia Center.

MR. LeBEL: Mark LeBel, Arcadia Center.

MS. ANTHONY: Abigail Anthony, Arcadia Center.

MS. WILSON-FRIAS: I'm Cynthia Wilson-Frias, Commission counsel, and while I'm thinking of it, the stenographer has asked that everybody try to use the microphone when they're speaking and try to remember to speak one at a time so she can get everything down.

MR. NAULT: Alan Nault for the Commission.

MR. BIANCO: Todd Bianco, still policy associate for the Commission.

THE CHAIRPERSON: I'm Meg Curran.

COMMISSIONER DeSIMONE: Herb DeSimone.

THE CHAIRPERSON: And we have an agenda?

MS. WILSON-FRIAS: We do. Today we're starting with a presentation by Arcadia Center and followed by another presentation by New England Clean Energy Council. During the last meeting we had been hearing a lot from National Grid during this process and we thought it would be good to provide an opportunity for other stakeholders to sort of set forth their goals and objectives for the revenue neutral rate design proceeding, and Arcadia Center and New England Clean Energy Council expressed an interest in doing so. So that's where we're starting.

At approximately an hour after that, this is -- it's an agreed-upon time, National Grid will be providing a presentation on the impact of different cost recovery methods using a hypothetical example. So for example, taking one amount that needs to be recovered through rates and looking at how the rate impact -- the effect on customers would be using two different methodologies of rate recovery. And then we built in a break for lunch, and then after lunch National Grid will be providing an update on the Tiverton system reliability project. So I think we can start with Abigail.

MS. ANTHONY: Good morning, and thank you for having us. I just caution before I get started that our printer got confused this morning and so some of the presentations are a little -- the pages are a little bit off, so I will just make sure to go slowly through those and make sure everybody is looking at the right thing.

So this morning we're just going to take a little bit of time. I'm going to go through Arcadia Center's Utility Vision which is a resource that we released late this winter meant to provide specific recommendations to stakeholders, regulators and policymakers who are interested in advancing the clean energy and consumer friendly energy system for the future.

So I'm going to move through that fairly quickly, then Mark is going to focus specifically on our recommendations that have to do with rate design, both how customers pay for power that they use and how they get compensated for power and other services that they provide back to the grid. And Leslie is going to tell you a little bit about some of the analysis that she's been doing specific to the issues facing us here and some of the next steps that we want to follow-up with after this.

So I think it helps just to provide a little context. We just want to explain why this is so important to us and how we got to the recommendations that we'll be sharing with you. So I'll do this very briefly, but I do want to back up to about 2012 when Arcadia Center analyzed the region's progress towards achieving the state's greenhouse gas emissions reductions. The result of that analysis became known as Climate Vision 20/20. It's a web resource that provides a lot of analysis showing what the states have been doing and how far we have to go to achieve our long-term climate goals.

What we found surprised us. We found that New England's power generation sector was actually quite a bit cleaner than we had expected in that the states had actually successfully achieved their early 2010 emissions reductions targets. Most of this was due to the transformation of our power generation sector. As you're all familiar, we had a large amount of fuel switching from coal and oil to natural gas. That made up almost half of a 44 percent reduction in total greenhouse gas emissions from power generation. The other half was due to the state's, Rhode Island's investments in cost effective energy efficiency and continuing to integrate great renewables into the grid.

So the key takeaways for me, for us from Climate Vision were 1, power generation in New England was down -- the emissions were down by 44 percent. We have a relatively clean power generation sector. But also, transportation accounts for more than half -- or almost half, 47 percent of the region's total greenhouse gas emissions and it remained a fairly stubborn and different place to reduce emissions from.

And finally, even though our energy efficiency programs are doing a really good job of weatherizing our natural gas heated homes, they're not reaching our oil heated homes as thoroughly, so we were still seeing large amounts of greenhouse gas emissions from our buildings and our transportation sector.

At the same time we were coming to these conclusions, we were also seeing rapid transformation in our consumer markets with new electric-based technologies coming into the marketplace that were readily available to consumers. So things like electric vehicles -- I was just saying last night I parked next to a Leaf and behind a Chevy Volt, hybrid electric heating technologies which presented a feasible alternative for the oil heated customers in this region. So when you combine these new electric technologies with a low carbon power generation sector, you start to see a pathway toward deep greenhouse gas emissions reductions from our transportation and our buildings sector based on a power grid and the power sources that we have today. And if we can continue to add more renewable energy to that power grid, those emissions reductions from transportation and buildings start getting lower and lower.

Oh, I should be telling you the slides to look at. So on the pathway to deep greenhouse gas reductions, this shows the analysis that we did. If we converted all of our conventional passenger vehicles to electric vehicles and all off our fossil fuel homes to high efficiency electric today with the power sources we have now, we could reduce emissions in those sectors by 50 percent overnight knowing that -- oh, and then if we continue to add those renewables, we can start to see a pathway towards reaching our long-term climate goals in 2030 and 2050.

Now, we know that we're not going to do this overnight, but we need to start laying the groundwork to achieve these goals. But the power system that we have today, as we talked about a lot, is designed for one way power flow, and the policies and the incentives that guide decisions that are made about the grid are also designed within that model, one-way power flow from our large power generators across poles and wires to our homes and businesses. This isn't a system that's designed for the high levels of bulk renewable power or high levels of distributed generation or this consumer adoption of new technologies and the engagement that we anticipate consumers will have with a new grid.

So we got involved in the Massachusetts grid modernization docket and New York. There are a lot of states who are signaling this direction to move to a more decentralized distributed energy future. But a lot of the proposals and the ideas were still centered on our existing regulatory framework, existing role for the utility and asking a lot of questions that were what we felt were sort of utility focussed. And that was natural, but we wanted to present an alternative vision.

In Utility Vision, our vision of the future, the consumer really becomes the central part of the grid. They're going to play a more active role. They want more control over their energy consumption and production, more control over their energy bills, more options. And so we started to think about how we could create -- if we were to suggest new changes to the regulatory system and to the utility business model, how would we make each of those decisions in a way that benefitted consumers the most?

And so came up with this illustration of our vision of the grid. Who wouldn't want to live there? But that's what the theme of Utility Vision is is putting consumers in the middle of the grid and designing our regulatory framework to be consumer friendly and environmentally friendly.

So Utility Vision is really based on reforms in three key areas. We see a need for coordinated utility planning for the future, and Rhode Island is already a step ahead on this we think with our system reliability procurement that we're going to hear about this afternoon.

Consumer protection and fair pricing for all. We don't think that a new utility future should degrade any of the existing consumer protections that we have with our current regulated utility model, but it should also provide rate design and compensation models that fairly allocate -- fairly compensate customers with the benefits they provide and that customers are paying for the services that they're getting. And we see updated and strong roles for regulators, utilities and stakeholders.

So I'm not going to go through all these recommendations; they're in Utility

Vision, but what we did was sort of categorize what we thought sort of this world of grid modernization was in five categories that made sense to us. I think it's helpful for putting boundaries on what we see is the issue. First, empowering the modern energy consumer. We think in the new utility future consumers should have more control, new opportunities, reduced barriers to embracing and adopting new technologies and innovations, but it should also be a safe place for consumers to interact either with the utility or with new markets that might be developing.

Strategic planning for a consumer-focused power grid. This is the idea that our traditional grid planning that is engineering and structural focussed needs to merge with what we call non-wires alternatives like we're doing in system reliability right now.

Aligning utility incentives with consumer and environmental goals. Regulation needs to change so that when a utility is comparing two different investment decisions, one in a substation or a feeder like in Tiverton and Little Compton compared with deep energy efficiency and demand response and rooftop solar, that there's a level playing field for those different options to be evaluated on. And that we do see a critical role for stakeholders in energy system planning in a similar way that the Energy Efficiency and Resource Management Council has brought a strong stakeholder oversight into our energy efficiency program planning and implementation of least cost procurement.

And so this is where I'm going to hand over the microphone to Mark and he's going to focus on our recommendations for the issues that are really relevant to us in this rate proceeding or in this proceeding, how consumers pay -- yep -- how consumers pay for the power that they use and how they get paid or compensated or credited for power that they produce.

MR. LeBEL: Thank you. Thanks for

letting us present today. So this is where the slides get a little confused. I'll start on the how consumers pay for the power that they use slide and then go to the how consumers get paid slide, and there's some overlap between the two the way we've done this Power Point. But we really wanted to think about where we want to be on electricity retail rates in 10, 15 years. So starting with some principles, and this is not necessarily an exclusive list on this slide, but electric rates need to be designed to allow and even empower consumers to make smart energy, economic and environmental decisions to save money and energy. So a few principles. We want to preserve incentives for energy efficiency and distributed generation, protect low-income customers, but still have fair payments for staying connected to the grid and fair compensation for services provided to the grid.

Now, on the how consumers get paid for the power they produce slide, distributed generation customers should be charged for staying connected to the grid but also credited for the full range of benefits they provide.

So the long -- what's the long-term vision? We need fully reformed retail rates for consumption, and that should be linked to the cost of the system, both environmental and economic. And so good options for reforming the current retail rate structures include time varying rates for energy, supply, including capacity, and then for delivery, that includes distribution and transmission. TVR is one option, but well-designed demand charges based on systems peaks are also another option. So then the second piece -- the first piece, that's just consumption essentially.

The second piece is what do we want for distributed energy resources and how do we fit them best into the system. And in the long run we do want bi-directional rates of some sort. There can still be a fixed charge, a customer charge for metering and billing and then you can have a charge for power consumed on a time varying basis, a credit for power exported on a time varying basis and then we could have new types of delivery charges. We're using the grid to consume and export power to the grid that reflects costs and benefits of each on both sides. So that's our long-term vision, and then when we think about the short term, we're sort of working backwards from there.

So that brings us to the next slide. Short-term recommendation No. 1. We really want to avoid reliance on fixed charges and minimum bills. We need to limit fixed charges to metering, billing and service drop costs. That's what's called the basic customer method I believe in the utility regulatory lingo. And we think you can actually go below that based on public policy objectives.

The other thing that's important is you want to have a transparent process and calculation method for figuring out what are those fixed costs of metering, billing and service drops so everyone can understand what's going on and other costs aren't sort of shoved in there inappropriately.

Second, on minimum bills, some states -- a lot of states do this differently. Rhode Island I believe currently has a minimum bill at the level of the fixed charge for DG customers because you can't net meter away the fixed charge, at least not at the retail rate, but other states do this differently. Massachusetts has a minimum bill of zero where you can net meter away the fixed charge and actually have a utility bill of zero for a given month.

So the next slide is the impact of higher fixed charges in Rhode Island, and these are some calculations that Leslie did, and if there are questions, she can answer them but she suggested that I just do it quickly for the sake of going through this smoothly. And this just shows that the blue line is the current rate structure. The orange line is a $10 fixed charge, and the green line is a $20 fixed charge. And you can see how increasing the fixed charge really increases the bills of low usage customers as you would expect. And then if you go to a $10 fixed charge, you'd be increasing the bill of 54 percent of National Grid customers.

And then that brings to us short-term recommendation No. 2 which is also very relevant to this coming docket. So we think that the way to approach the problem of distributed generation and their contributions to the grid is to better reflect the rate values. So we think that the output from distributed generation should be credited for its grid-wide costs and benefits and that includes avoided energy, capacity, transmission and distribution, environmental compliance costs, but then credit values should also reflect the costs of using the grid to consume and export power. Over and beyond that you can also have additional incentives to reflect environmental and societal benefits and offer further support for certain industry segments, community solar, low-income, that kind of thing, and those types of further incentives should also be considered.

Along those lines we started doing -- on the next slide is the grid value of solar PV in Massachusetts. So we've started doing state-by-state analyses of what is the value of solar located in particular places. So we started in Connecticut and this shows our numbers from Massachusetts. And we looked -- and this type of study has started to happen all across the country in Minnesota, Maine did a recent one, Vermont and California have done very similar studies in different contexts, but looking at each component of the actual costs to the system that an additional unit of solar avoids. So we have energy, capacity, DRIPE for energy and capacity, avoided distribution and transmission costs, and then you have both environmental compliance costs and environmental externalities.

So on the next slide titled Additional Considerations which are still very focal to this docket, the legislative framework for this particular proceeding and the one that's going to start in a month or two is limited to distribution rates, but we really think that rate reform needs to be evaluated in a broader context. If you're changing distribution rates, if you want to be fair to solar, you need to adjust the other pieces of it as well. Any long-run ratepayer values provided that isn't included in the retail energy credit. You can also start making the system smarter at the same time by having new credits for west-facing solar that help reduce peak demand because they're better aligned with the times that have high demand on the grid. And then you can have other distribution level credits to reflect geographic areas of need such as the system reliability zones here in Rhode Island.

And then that brings us to our conclusion. We really feel that rate design should maintain marginal incentives for using energy wisely and even generating energy wisely. Consumers should have the ability to control their energy bills by making smart decisions. In the short run, we want to adjust compensation to distributed generation to better reflect benefits and costs. And in the long run we need to figure out more systematic reforms for retail rates.

MR. BIANCO: Are we going to do questions now or did you -- Leslie, were you going to go next?

MS. MALONE: No. No.

MR. BIANCO: Just a couple of quick questions. Abigail, the GHG emission reductions, was everything you showed for New England or was there a breakdown?

MS. ANTHONY: In this slide with the green and the two houses?

MR. BIANCO: Yes.

MS. ANTHONY: This is for the

Northeast as a whole.

MR. BIANCO: And should we interpret that none of the GHG reductions were due to the financial economic crisis? This is the reductions before that?

MS. ANTHONY: The existing or the potential are you asking about?

MR. BIANCO: The existing.

MS. ANTHONY: The existing. We did account for any greenhouse gas emissions reductions that were attributed to the recession, to the economic condition situation, but that the conclusion of that analysis is that they -- the emissions and economic growth have actually become decoupled in a way that they were moving in different directions. So the region as a whole was seeing economic growth at the same time it was seeing falling greenhouse gas emissions reductions. So that situation may be slightly different in Rhode Island specifically due to both increased power generation under RGGI and our own economic situation.

MR. BIANCO: You can say it.

MS. ANTHONY: But for the region as a whole they were going in separate directions.

MR. BIANCO: Mark, in your conclusions when you say rate design should maintain marginal incentives for using energy wisely, so you've discussed having time varying rates which I think makes a lot of sense for somebody who's intending to sell energy. I wonder. Do you mean this also for just the regular standard offer customer should they be -- currently we have six-month and actually 12-month rates this year for residential energy. Should we -- should the Commission take that as a recommendation to move to time-of-use rates and energy that we're getting from the wholesale market, for example?

MR. LeBEL: Yes. I mean, things like basic service, you should definitely consider moving to time varying rates for that piece of it, too. One of the key drivers of system costs and energy and capacity markets that those numbers are based on is the time of usage. So if you want to start to control those costs by having customers react, it's appropriate to consider sort of a new way of doing things.

That said, we do think it's important to phase that in, to figure out what the bill impacts would be for certain people. Shadow billing. There's other things you can do. And then you can start with bigger customers who you feel you would get a better bang for your buck, and you also need to consider metering costs. So there's a lot of different angles to that question and how fast you can get there.

MR. BIANCO: You don't imagine a split between folks who wish to be in this new energy vision and folks who want to stay in the black and white world as basic customers as a separate class? They just want to be load, have a relatively stable rate. Do you imagine that this needs to apply for all residential and commercial customers so that we don't have these huge over and undercollections possibly?

MR. LeBEL: I think there's a question of whether we're talking about five years from now or 20 years from now.

MR. BIANCO: Let's talk about both.

MR. LeBEL: So five years from now or ten years from now I can imagine still having opt out or opt in, and then in the long run when we have kids and grand kids -- no? Shouldn't go there, Todd?

MR. BIANCO: Not after last night.

MR. LeBEL: And the other angle to this is when we have different end use technology that could interact with the electric system, it will make it a lot easier to make these things automatic where you don't have to go around switching off light bulbs when the time-of-use price changes or whatever you would do. In 30 years your house will make all these decisions automatically. So I think there's major technology changes and a little bit of cultural change that will have to go along with this.

MR. BIANCO: I just have one more. Do you see any limitations with the -- with distributed rates we have a utility, but with energy there's a competitive market and they're allowed to offer whatever products they want. In Texas, for example, they're all in the competitive market and some of the products are if you peak shave during the day, we give you free energy at night, run your air conditioner all night. Do you see in Rhode Island that limitation in that we have both provider of last resort service which actually accounts for most folks and at some point maybe we'll have more folks, we'll be more like Connecticut with half and half. With the energy side of the bill does that present a limitation of what can really be done. Because the products that the market offers are intended to be not touched by anything that the PUC or Division really does at this point.

MR. LeBEL: It's a lot easier to have a top down approach if you're still in a fully regulated market. Once you do restructuring, there are a lot of new angles there in how you allow third-party suppliers to come into the picture, who controls the billing. And then if you have a third-party supplier, what does the metering enable? What can they actually offer that makes sense? What information do they get that informs what they offer? So there's a lot of different wrinkles that make it more complicated when you're in a restructured market, but we still think that overall principles apply and we sort of want to start heading things in a direction that makes sense for the whole system. So it does introduce some new wrinkles.

MR. BIANCO: Do you think it makes sense, then, to allow either -- either side, say the regulated side or the competitive side might innovate products and if you were to limit that ability to innovate, for example, if there were mandates for the regulated side to be more like the products that are offered on the competitive side to make it more simple for customers to compare? I mean, do you see that as a limitation?

MR. LeBEL: Well, yeah. So there's important questions about what customers will understand and be willing to accept that are very central to all of this. In Connecticut there are major concerns about retail suppliers ripping people off when you get to higher levels of retail suppliers. So there's -- you know, how much time do we have right now? We could -- it certainly gets into some very tricky areas of consumer protection and what people understand and how can they actually make good decisions.

MR. BIANCO: Thank you.

MS. WILSON-FRIAS: Could I just ask? I have a follow-up to one of Todd's questions and the response. You were talking about the fact that in, say, 20 years, time-of-use rates could be broad and rather than an opt in or opt out, and you were talking about better technology that can interact with I guess the utility company or with the meters. Is there an assumption underlying all this that that technology will be economically available to all customers? So it sort of goes in with the consumer protection for low-income customers.

Are we in a world right now where we're -- we already have customers that have difficulty paying their bills or they have other economic challenges. They don't have access to all of the products and services that are available now. And in terms of looking forward, are we almost creating a wider divide to start with going down this road with the expectation of a lot of this working with new technologies and -- it's more of a philosophical question.

MR. BIANCO: But also, nor do they have the credit to play in the type of markets that we might be talking about.

MR. LeBEL: I can start and Abigail might have some additional thoughts. So I've talked to consumer advocates, "Do you think the low-income people would be left behind if they aren't able to get smart meters, for example?" And he goes, "Well, they don't have Lamborghinis either." That's one attitude you can take. I think it might be better to focus on the other side of it whereas you have low-income programs that help them get the smart refrigerator just like -- I'm not sure in Rhode Island specifically, but Massachusetts has a very robust low-income energy efficiency program. Connecticut has something similar but maybe not quite as good where you help the low-income people get the better appliances that work with the energy system. So I think there's two possibilities here. Either you leave them in the black and white world or you help bring them into the color world.

MS. WILSON-FRIAS: Do you need broadband to work these particular devices? You need that? So that would be another aspect of connectivity.

MS. ANTHONY: I would just add that Utility Vision doesn't envision the deployment of technology for the sake of technology. Like, we saw in telecom in the cellphone revolution, technology will drive change. It already is. It's coming into the market. People want it. But we don't see the -- for us, the end goal is not just to have these new things because they exist. The goal is to have a cleaner and lower cost energy system as a whole, and we'll include transportation and buildings in that calculation of a lower cost total energy system.

So the deployment of technology, including advanced metering which can enable a lot of changes to how we consume, produce and pay for power is that the benefits should exceed the costs. And so as we think about moving forward, and as you deploy both the rate innovations or the objectives that we would like our regulated utility to achieve, those should all be thought out in the context and guided by a cost/benefit analysis that's comprehensive, that includes the full range of costs and benefits as we do in energy efficiency programs. And this might indicate that -- as Mark said, we use a phased or strategic approach where you're addressing the most cost effective customer sectors first where you need more time in order for other customer sectors to become more cost effective as people learn or are educated or the technology costs come down over time. But I think the primary objective is not to deploy technology just because it exists but because it enables lower costs and greater benefits to consumers.

MS. WILSON-FRIAS: I guess part of what raised this for me is -- I haven't worked on an energy efficiency case since 2005. Back then we were struggling with delivering demand side management programs to low-income customers, renters and that sort of thing, and what I hear from people who are working on the energy efficiency cases now is that that challenge is still there ten years later and that challenge has always been there. And so I wonder how these innovations -- how the expectation is that these innovations would be delivered to those same subsets of customers where the programs in place for the last -- a very long time, more than ten years, probably 20 are still facing those delivery challenges, and so that's sort of where the question comes from.

MS. BESSER: Cindy, maybe I can respond. This is not my strong suit, technology, but I'm going to speak to it anyway. I think one of the key things with reaching low-income customers, there are different ways to deliver benefits to low-income customers, and if we haven't sent this to you already, we can send you a consultant report that NECEC filed in the Massachusetts time varying rate proceeding that really addresses some of the issues around low-income customers and do they benefit from time varying rates.

And one of the key things as you think of deploying this technology is there's one way to say that everybody benefits if every single customer has the technology. But another way to look at it is the way we've talked about energy efficiency system benefits for a long time. So not every customer has to have the technology, has to be taking advantage of time varying rates in order for all customers to benefit.

So one of the key things that time varying rates can do is that it reduces peak consumption. Peak consumptions lowers the cost of the entire system for all customers. So that is one way in which low-income customers can benefit.

I haven't done energy efficiency programs in a longer time than 2005, but I think that some of the discussion there and some of the models for distributed energy resources are how to give low-income customers access to solar, so community shared solar programs. So there are ways to get around some of the problems that don't involve putting solar on a low-income customer's house but allows them to take advantage of benefits that solar can provide.

So I just offer that thought that as you think about the benefits and costs of new rate designs, new technologies, advanced metering, it's not just that -- think about the broader impacts. And some of the analysis and statistical analysis that's been done show significant benefits for all customers from time varying rates even if an individual customer is not participating.

The other key thing with this analysis that Armand Feruki did for us is that low-income customers generally subsidize now higher income larger customers because low-income customers' pattern of usage is less peaky than the high income customers' pattern of usage. There's a whole volume difference, but there's also a time difference of usage. The low-income customers, because of budget constraints, are already trying to reduce usage and so, in fact, pay more in some hours than high income customers.

MS. WILSON-FRIAS: This may be a

better question to save for Jeanne Lloyd later, but it was sort of referenced in the presentation. Would this be where you suggest looking at demand rates for residential customers?

MR. LeBEL: Yeah. I mean, in the long run when there's smart metering for certain classes of customers, demand charges based on system peaks should definitely be strongly considered.

MR. BIANCO: It just occurs to me that in thinking about those benefits, often times while a cost/benefit analysis would still be greater than one, let's say, the -- to maximize benefits you often have to cut out certain users which might be low-income. So while overall the ratio might still work, sometimes maximizing benefits -- and I think that depends on what you limit your definition of benefits to. And I wonder if you have an opinion on whether or not in these types of -- you know, 15 years from now your visions, I guess, should the utility ratepayers be paying for societal benefits as well as -- or should that be upon taxpayers?

MR. LeBEL: Well, we went from the low-income thing to the social externalities, so I'm not sure where to start. So to start with, the first thing, I'm not sure I agree with the premise entirely, and it depends on how you do things like community solar and other parts of the program that you can sort of try to design around that issue. But there's going to be a case-by-case investment-by-investment kind of thing. And on the social externality part, in other states I'm not sure how -- what stance we've taken on this in Rhode Island -- we do think that the cost of meeting state level greenhouse gas goals, targets, requirements, whatever you want to call it, is a relevant ratepayer consideration and consumer consideration. The social externality piece of it shouldn't necessarily go into rates, but as we shift towards situations where greenhouse gas limits are more binding, we do think that some of those ratepayer cost items would be higher for greenhouse gasses to pick a hypothetical example about what sort of social externality you were talking about.

MR. BIANCO: Actually, I wasn't talking about that one. For example, if you were to have better outcomes for low-income ratepayers such that they might have lower arrearages or lower defaults, that's certainly a benefit to other ratepayers. However, if you were to lower their bills such that they have more money to spend on other necessities and that benefit flows to taxpayers because really stuff like healthcare and basic needs like food, housing are paid from taxpayers, not ratepayers, so taxpayers get those benefits. Should taxpayers be asked to chip in on some of these in that sense or should it all fall on ratepayers, and the cost/benefit analysis, if it passes, it passes and ratepayers should pay?

MS. BESSER: If I can offer a

thought on that. I think it depends on what you're including in your benefit/cost analysis if that was what your question was about. I actually heard it differently as well. I think as you make a decision as a regulatory agency as to whether you provide a low-income discount and that discount is picked up by other customers, in my experience, that kind of analysis focusses on reduced arrearages, reduced costs to the utility company which clearly go to the benefit of other utility customers. I can't think of an analysis, maybe the Grid people know, where the rationale for a low-income discount for electricity customers was that they then would have more money to spend in the rest of the economy and that that was the benefit that justified having low-income discounts. That's an area where I think in my experience the benefit/cost analysis has stuck pretty closely to benefits and costs that accrued to either the distribution utility or to all the customers.

I thought you were asking the

broader question. There is social policy that we do through electricity rates and we have done through electricity rates for 50 plus years. I don't think Rhode Island is the worst of the states in these areas. New York has often held up as the model of -- they don't want to raise taxes generally so they just tax the distribution charges of utilities, and National Grid can speak to this in spades because it's a challenge for the utilities to then go and say you know, "This rate increase you're getting has nothing to do with us, but we just got slapped with another two percent tax to balance the state budget." I don't know that -- I don't think Rhode Island has done that. So that kind of thing I think it's important to try to avoid. But where there are externalities that are a consequence of electricity production and use, those are properly I think brought into a benefit/cost analysis and how you set electricity rates.

MS. ANTHONY: I'm not even sure weather this is worth bringing up and folks who are -- maybe National Grid will tell me I'm totally wrong, but I think that if you -- I think I'll save it for later.

MR. BIANCO: It's not like you're on the record or anything.

MS. ANTHONY: My thoughts were not fully formed yet.

COMMISSIONER DeSIMONE: Good time to switch to the National Grid presentation?

MS. WILSON-FRIAS: I think actually for New England Clean Energy Council.

MS. BESSER: Thank you, Cindy. So you have in front of you a one-pager, not as elegant as the Arcadia slides, but one of the reasons that we wanted to delay this presentation was for the Massachusetts net metering and solar task force to conclude its deliberations and issue its report which it did on April 30th.

So one of the things that Cindy asked us is what is our vision for what we want to see out of this proceeding and how do we want to see rates designed here in Rhode Island in a way that is going to accomplish a variety of goals. And I think the two overarching goals are that there is fair compensation to distributed generation for the value it provides to the system and fair compensation to the distribution companies for use of the distribution grid.

So certain circumstances in Massachusetts and Rhode Island are a bit different. And Mark mentioned in Massachusetts you can net meter away your entire bill, including the customer charge, so there are customers in Massachusetts who pay a zero bill. Here in Rhode Island that's not the case. You continue to pay the customer charge. I think you -- so you can net meter away the customer charge here as well for some customers? Okay. So then some of these issues are going to be the same.

So when that happens, you know, the customer is essentially using the grid as a big storage device because its usage doesn't always match up with its production. So how does it pay for that? So the Mass. net metering task force report actually reached consensus on principles that are on the back side of the page for fair compensation for use of the distribution grid. But it's important to understand that in the context of some of the language that's on the front side of the page because all of this language was carefully hashed out. I didn't even want to abbreviate it for fear of leaving out some word that was essential to one of the many parties involved in the process. And it was a task force of 17 people, representatives from the utilities, National Grid and Everforce, New England Clean Energy Council, the National Consumer Law Center on behalf of low-income customers, associated industry in Mass. on behalf of business customers. The municipalities were represented, the unions were represented, several legislative representatives on the tasks force, the Attorney General's office who works as the consumer advocate.

So one of the positions was what

should net metering compensation be about? And it's about fair compensation for the value that solar provides to the grid. Position 1 reflects where there wasn't a consensus position. This one was the majority position. It wasn't shared by the utilities, but it was about the fact that there should be a comprehensive solar benefit/cost study in order to figure out what are the various value streams associated with -- in this case the focus was solar, but it could be standard to all DG, and I think Mark laid out in the Arcadia slide the value of solar analyses that Arcadia has done.

The other big issue in Massachusetts which is not an issue here in Rhode Island is net metering caps. So right now there are caps on the amount of -- percentage caps based on load for net metering. Those caps have largely been hit in the National Grid service territory. So the immediate issue in Massachusetts is removing the caps, and part of that was you don't need caps if you have the fair compensation for use of the grid and the fair compensation for services that customers provide to the grid through distributed generation and about that underlay the renewable energy growth bill last year and led to this proceeding because the agreement that National Grid made at the time to eliminate caps on net metering here in Rhode Island relates to the fact that we're going to have this proceeding and figure out what is the fair compensation for use of the distribution grid.

So if you turn to the second page, you'll see that this is really -- the principles seem obvious, but it actually was carefully worded, that the task force members agreed that everyone who's connected should contribute toward the use of the grid and towards the system benefits charges that are included on the distribution company bill for public policy reasons.

So there's a low-income discount, there is the energy efficiency charge, there's renewable energy charges and some might argue these are the charges that relate to the discussion we were just having of funding energy efficiency programs because, in fact, there are benefits to the electricity grid as a result of that. And the way they are collected is on a cents per kilowatt hour charge and, therefore, all customers should be paying that. But for customers who net meter in Massachusetts you don't end up paying that. Am I correct that in Rhode Island, in fact, the net metering credit deducts the energy efficiency charge? I think it will going forward.

MR. ROUGHAN: It's the same as Massachusetts.

MS. BESSER: So fewer differences than I thought. One of the principles is that the fair compensation should apply to all customers. So there was discussion about whether solar customers or DG customers should have their own rate class and, in fact, the agreement was they shouldn't be distinguished unless when you're setting up rate classes, and Jeanne and Terry and the Grid team can tell you more about this is, when you have different classes when there are distinct patterns of uses, distinct different circumstances for customers, but if you were trying to lump all customers who have distributed generation, in fact, some of them are residential customers, some of them are commercial customers, some of them are industrial customers. They don't I think meet criteria that would constitute a special rate class for DG customers. So the result was fair compensation should apply to all customers.

If, for example, it's something like a minimum bill, its impact will be different on different customers. So if I'm a customer who uses 100 kilowatt hours a month, it costs me $100, just assume for simplicity sake, and the minimum bill is set at $10, then it doesn't mean anything to me because I'm always paying more than $10 a month so I don't see any impact of that.

But if I'm a customer who installs solar and I take my former $100 a month bill down to $6 a month but the minimum is $10, then I'm going to pay $10. So there's a $4 difference that I would see if I were that customer and there were, in fact, a minimum bill in place. So that's just a very simplistic example of why -- of how a policy applying to all customers will definitely impact customers differently based on their different usage.

One of the other principles is that any level of charges associated with fair compensation such as a minimum bill or a demand charge would be reflective of the size and usage pattern of customers and would be mindful of low-income customer issues. So the same minimum bill wouldn't apply to our grandmother and her 300 square foot apartment as applies to your cousin who made it big and has a 5,000 square foot house. So there you have -- you want to tier your minimum bill is I think the term that National Grid has used. Then obviously for commercial/industrial you're doing the same thing.

Specifics of rate design and rate level should be consistent with principles of efficiency, simplicity, continuity, fairness and earnings stability based on long established rate making principles. We're not talking about deviating from that. But that seemed to be an important thing to say.

In addition, there needs to be transparency and understandability so the customers understand what's on their bill. That doesn't mean that you have a long, complicated bill that lists every single little component of the charges. That does not enhance understandability for customers. But when you're talking about it in a general way, you can actually explain it to somebody in an elevator without ripping out spreadsheets as to how you're doing this. I'm being a little facetious and a little simplistic here, but the idea is that regular people can understand what we're trying to do with rates.

There's the mechanics about rate cases are not so important whether it be a rate case or a rate revenue neutral rate design proceeding such as this one, and in Massachusetts grid modernization filings are due in August, so that was offered up as an opportunity for setting these -- setting fair compensation and that obviously gets reviewed in every rate case.

So I think the other couple of principles I want to discuss are -- and I think that Mark touched on this. You want to provide fair compensation for distribution companies in a way that does not undermine incentives for customers to take advantage of distributed energy resources, and by that I include energy efficiency, demand response and solar. So there are proposals around the country for high fixed charges. That in and of itself means that it can undermine the economics of choosing to do energy efficiency or distributed generation for customers. But if you're going to be revenue neutral and you implement a high fixed charge, then you are lowering the charge per -- you may be lowering the charge per kilowatt hour and, again, that would be at odds with a goal to encourage customers to use energy efficiently. So lots of details there. Time varying rates can be structured so that you provide better incentives to the customers, certainly layer are on with -- that can be combined with some kind of minimum bill as well as implemented on its own.

So some of the options that are consistent with these principles are a minimum bill-type construct. There's been lots of discussion about fixed versus variable charges. I think NECEC would prefer a minimum bill over a fixed charge, and going back to my simplicity example, if there's a fixed charge of $10 and I'm using 100 kilowatt hours, $1 a kilowatt hour, my bill becomes $110. So that, in fact, that's the difference between the impact on a customer who doesn't change usage from a fixed charge that's added on versus a minimum bill which just means as long as I'm sort of floating above the level of the minimum, I don't see any difference. You can see various netting options that can take place. So even as you do all of this analysis for small customers, particularly for residentials under 25 kW, you may not change anything about the way net metering works because you're close enough, and again, this gets to simplicity and understandability of customers so that the value provided is close enough to the service used and you continue to net meter in the way that we've understood it today.

I think some other considerations talked about transaction costs and complexity. So for the small customers you might want to do something like that. You want to talk about affordability.

One of the other big elements that I think this proceeding can provide a path to addressing is the fact that at the same time that we're seeing the broader and broader deployment of distributed energy resources, there's the discussion about grid modernization and having the distribution company make investments on the system that will actually facilitate the integration of these distributed energy resources, so they'll be more valuable to the utility as well as more valuable to all of the other customers. So we have had public policies that promote this, but, in fact, the distribution utility hasn't had the opportunity to make some investments that would make all of this more valuable.

So for example, what the discussion in Massachusetts was was yes, we would want to give locational incentives to distributed resources to locate on those circuits where they could provide the most value and they may, in fact, in a planning process obviate the need for an investment in a substation. The companies has acknowledged that right now they actually can't tell distributed energy resources where that would be. They can't tell DG and solar because they don't have the capability on the system to know that yet. So that's an investment that they're going to be required to make and that's an investment where the value or benefit of them being able to direct DG to better locations should be counted against the cost of making that investment. It's going to be a big challenge, but I think part of the discussion we're talking about here is how do we -- one of benefits of modernizing the grid will be better able to use and direct the location of distributed energy resources.

So I think that concludes my formal remarks, but I think that's what I think this proceeding is a precursor to saying as we think about designing these rates, we want to think about that in the larger context of grid modernization. So thank you. I'm happy to answer any questions.

MS. WILSON-FRIAS: I guess we've had a lot of discussion so far with -- around net metering and how it would be credited and the differences in Massachusetts and Rhode Island, and I wonder, first, can anybody tell me, in Massachusetts was it the legislature or the DPU that set how the net metering credit would be calculated?

MS. BESSER: In Massachusetts it was the legislature. It was legislation.

MS. WILSON-FRIAS: Okay. So just like in Rhode Island. Have you looked at it to see if there's any constraints -- let me backup and rephrase it.

In Rhode Island we have the net metering law and there's -- the credit is set out and there's been discussion of changes that might need to be considered with net metering. Have you looked at whether or not the law provides any constraints to what the vision is that you have?

MS. BESSER: The law here in Rhode Island?

MS. WILSON-FRIAS: Yes.

MS. BESSER: No. I think here what

we're talking about -- I haven't looked at it in that way. I'll be honest about that. I think here we've been focussed on this proceeding and the opportunity to ensure -- address the utility's concerns about fair compensation for use of the distribution grid in light of the way the law is structured. I think we just modified that last year. And from the perspective of clean energy developers and providers I think we're not seeing any changes there, but we've acknowledged that within the construct of what's before the PUC, you can make a change in how the -- to ensure the distribution utility is seeing its fair compensation.

MS. WILSON-FRIAS: Okay.

MR. BIANCO: I had a couple questions. So talking about fair compensation, I mean, if some of these distributed energy resources were to take off like gangbusters -- it's an industry term -- how do you envision the compensation for a utility that did not have that opportunity to invest in plant but rather avoided the investment in plant?

MS. BESSER: I'm not understanding. So there's lots of DER here in Rhode Island.

MR. BIANCO: Let's say I put in a renewable energy resource, I pay for the interconnection and I have eliminated the need for a new substation, a new tap line which is how a utility makes money, right? I mean, they build a plant and they earn --

MS. BESSER: Right.

MR. BIANCO: Do you have an idea on what that fair investment looks like in the future where lots of utility investment is not necessary because of user investment, ratepayer investment?

MS. BESSER: So we've done a lot of thinking about that and that actually is the big question. The elephant in the room as we proceed down this path is what is the future utility model going to look like and what is the future regulatory model that is actually going to align the interests of customers who are installing distributed energy with the interests of the distribution utility that to date makes it money based on its capital investment in the system. So I think NECEC has commented on this issue in Massachusetts and in New York in terms of things like time varying rates.

With National Grid, in fact, we developed a utility of the future regulatory model that if we haven't shared that with you, I'd be glad to share that with you. This was in a report that we provided to the Mass. DPU in the summer of 2013. Interestingly, a number of the elements of that model are here in place in Rhode Island; they are not in place in Massachusetts. So it involves things like forward looking test years. I think what needs more work are performance metrics and incentives. Recent discussions, presentations I've heard folks from National Grid give in other contexts talk about the -- moving the incentive from CAP-X, making it -- there's TOT-EX is the latest phrase that's being used, but enabling utilities to make a decision versus a capital versus an operational investment and not have this bias towards a capital investment which is not a bias because they have bad intentions, but it's, as you said, how they make their money. They're a business that wants to be -- and we want them to be doing well, and so, therefore, I think there's a number of different regulatory constructs. And I'm pretty sure we've shared our white paper on grid modernization, too, but it also addresses these issues.

MR. BIANCO: Can I ask, on the back page of this handout under the fair compensation for use of the distributed grid, Point 4 is fair compensation mechanisms should be designed appropriately for low-income -- I'm sorry. I'm reading the wrong point. Point 3. The level of any charges associated with a fair compensation mechanism for a group of customers or rate class should take into account customer size and/or other service characteristics in order to develop appropriately sized contributions. So I can read, which is good. But -- so maybe I'm reading too deeply into it, but I want to propose an end member model, right, in which -- well, first I'll say it seems to me that as more DG or more of these resources come onto the system, there is less and less or decreasingly increasing benefits to all other customers possibly, or maybe it ramps up at first and then sort of decreases to the point where at some point imagine an end member scenario where all ratepayers had systems that sold as much energy onto the system as they needed and so you have a minimum charge, or in the case where no minimum charge, literally nobody owes anything for, you know, what is a few hundred million dollar distribution system.

When you think about that group should you take -- rather than look at individual systems and saying this is what the system provides with time-of-use rates, I mean, do you need to look at this is what this level of uptake of these types of systems provide and allocate costs that way?

MS. BESSER: Okay. So this is the scenario that gets played out as the EEI's disruptive challenges report from January of 2013. This is the death spiral --

MR. BIANCO: Of course.

MS. BESSER: -- scenario that's out there that I've heard for the 25 years, 30 years, actually, probably now that I've been in the business. It started with Seabrook was going to cause the death spiral because rates would go so high and all the customers would leave. And do you know what? I don't think it's going to happen. Here's the rationale. One, if -- you're not setting your rates right if, in fact, every customer can leave and no one is left paying the bill. NECEC is not suggesting something like that. In fact, short of a real technology innovation that we haven't seen yet that I compare to the -- I think it's called the flux capacitor in Back to the Future where you can take your banana peals, throw them into this little thing that looks like a coffee maker and run your car and run your house. We're going to need a distribution grid and we're going to need wires and, therefore, we're going to have to pay for those. And every customer -- I shouldn't say every. The vast majority of customers that have installed distributed resources remain connected to the grid and they should pay for that service. So therefore, we're not suggesting a construct where net metering means that you're always running the meter backward.

In terms of if you have time varying rates, what's going to happen is you would be paid more when your power that you're producing is worth more and you would pay more if you were using power at a peak time. Money will keep changing hands. We're not suggesting a scenario -- if you want to cut the cord to the grid, then you don't have to pay anything for the grid. But that's very, very few customers. So I've said something here and certainly the intent here, as Peter can attest because he was participating in the Massachusetts project, there's no intent here to somehow come up with a scenario where customers don't pay for the usage of the grid. In fact, just the opposite. I may have misunderstood your question.

MR. BIANCO: No, I don't think you did. What I mean in addition to that, which I think it was good that we discussed that, is just you would agree, though, at least, that -- I mean, the more -- at some point the benefits of additional distributed generation start to decrease.

MS. BESSER: If the benefits of more DER decrease, then the value that they're providing is less and the payment or compensation they get would be less, so I think that it will depend. There may be circuits where more DG -- actually, we've seen this in Massachusetts. You can't put any more DG on a circuit because there's already too much generation on a circuit that wasn't built for generation. Part of what we're saying is let's give the utility incentives to start to build out its circuits so there can be two-way power flows, but at that point, I'm sorry, if you want to connect DG, you can't actually net meter, and frankly, you can't even connect it to the grid because you just can't do it. So that's happening for Unitil's service territory in Massachusetts in some circuits and in Southeastern Mass., which might be Eversource's territory --

MR. ROUGHAN: The land of Eversource.

MS. BESSER: The land of Eversource, yes. So yes, when you are putting too much of anything on the system and it makes no economic sense, you're not going to pay it.

MR. BIANCO: Right. Okay. So --

MS. BESSER: And likewise, we wouldn't want to pay National Grid for overbuilding distribution. I just had to be evenhanded.

MR. BIANCO: So in that sense would that be -- maybe there's no caps suggested in benefits or payments, but I mean, at some point there should be caps on the limitation of the amount of DG based on -- to the extent that they provide benefits on the circuits they're connected to.

MS. BESSER: No. So what I would say is there's no need for a net metering cap. There's no need for -- well, the cap on DG will be the technical ability to interconnect it. So if a circuit can't accommodate another solar generator, it can't accommodate that without hurting the reliability of the grid, and Tim probably could explain better than I why that's the case. So then you're told, "No, you can't connect." I'm on a street right now where I'm trying to get gas service. There is no pipe in the road so I can't get gas service. There are certain physical constraints in the system, the electric and the gas system, that we're not suggesting you somehow magically ignore or try to overcome. Some people will not be able to interconnect.

MR. BIANCO: So to respond to that,

though, so the current renewable energy programs in Rhode Island, if they were to continue, actually do account for that, right? I mean, as customers try ever increasingly complicated interconnections, that will eventually be picked up in the average prices of interconnection which will be reflected in ceiling prices.

MS. BESSER: Seth could speak to some of this, but what happens in Rhode Island and pretty much everywhere else is if I'm making a bid into the Rhode Island renewable energy load program and the cost to interconnect my project is going to be really high because I'm on a circuit that's limited, then I'm not going to win the bid because the cost of Abigail's project which is on a circuit that really has plenty of room and actually could benefit, she's going to be able to put in a lower bid because it's going to cost her less to do the project.

MR. BIANCO: But if those large projects have nowhere to interconnect except expensive places, one might say well, then, no large projects are economically beneficial in Rhode Island. What I think the renewable energy growth program would allow for is for the ceiling price to go up to accommodate those projects.

MS. BESSER: I don't think I'm completely understanding the scenario you're playing out. So if the ceiling price goes up because the cost of -- I'm not going to remember the numbers for Rhode Island, but a large Rhode Island project is X.

MS. PENNOCK: Two megawatts.

MS. BESSER: Two megawatts. So it's a two megawatt project and the ceiling price for a two megawatt project is set by the DG Board at --

MS. PENNOCK: $.17.

MS. BESSER: $.17. Okay? And what you're saying is because we've used up all of the space on the distribution system, the ceiling price would have to be $.25 because it costs eight more cents to interconnect anywhere. Part of what you're going to do with that $.08 is -- the reason the DG guy is going to need it is because he's going to be paying it to National Grid to update the distribution system so they can interconnect.

MR. BIANCO: What benefit would that provide to everyone else in that sense? It's not the same as DG coming on and eliminating the need for capacity or selling energy otherwise -- when it would be otherwise be hard. It's actually saying we're going to build out so that we can accommodate --

MS. BESSER: Build out the distribution system so you can accommodate larger projects that are going to have a whole lot of benefits that are in Arcadia Center's back-in benefits. If you get to the point -- I'm not going to be able to turn to the page quickly, but if you get to some of those benefits --

MR. LeBEL: I think the point is at some point you run out of benefits from additional solar just like you run out of benefits from additional nuclear plants or additional anything else.

MR. BIANCO: Right. So that should be reflected in any kind of design of minimum charge, no charge or fixed charge.

MR. LeBEL: Any rate design has to be updated every -- pick a number of years.

MR. BIANCO: That's the hard part because people are making long decisions on these installations.

MS. BESSER: If you make a decision at a point in time where the economics for you, you are entitled to that rate for the period of time, that rate class. The dollar value of the rate may change. That happens with net metering now. So this winter people who were net metering got more revenues than they got last winter because electricity prices were higher, the retail rate for electric prices. So that kind of fluctuation will take place as rates go up and down.

So as I make a decision about investing in DG here today, say electricity

-- we -- while they're digging the foundations for the Block Island project they hit natural gas pockets and suddenly Rhode Island is exporting natural gas to the rest of the region and electricity prices crash everywhere in the region. If I put in solar, I'm going to get less money. But I'm still entitled to my --

MR. BIANCO: No, you're not. I'm sorry. You actually wouldn't under the REG, and that's the point. I pose to grid, why would anybody net meter? On a financial decision why would you ever net meter as a residential if you need $.42 per kilowatt hour to make your money back with a reasonable return? That's what's approved as a ceiling price.

MS. BESSER: So you'll get the ceiling price here for the 15 or 20 years of the tariff and that's based on a reasonable projection that it's probably pretty unlikely that we're going to hit gas in Nantucket Sound. So yes, you're right.

MR. BIANCO: I guess I don't

understand.

MS. BESSER: But it's time limited.

MR. BIANCO: It's not based on my projection of this miracle happening. It's actually based on the cost of the installation plus a reasonable rate of return as we do with regular utility regulation. Net metering, however, is a guess based on whether or not energy prices might go up or down and I'm pretty sure it's socially, whatever your decisions might be, but I think for residential if you're telling me $.42 is what's necessary, net metering is a loser because we've never seen rates like that.

MS. BESSER: Let me just say one thing in response to that and then I'll let Jerry respond. So one of the things that goes on in the Rhode Island program and in other programs is there's two components to the compensation for distributed generation. There's the fair compensation for the value it provides for which net metering has been a proxy, and then there are additional incentives on top of that that are part of public policy because, in fact, we think that building that industry is going to lead to lower costs and benefits for future.

So in Rhode Island that's the REG program and the way the incentive level gets set and the net metering is netted from that. In Massachusetts you have the net metering stream and then you have what's called the S-REC or the solar REC stream of incentive payments on top of the fair compensation for the solar for which net metering is a proxy. So what we're talking about, and I'm sorry if I wasn't clear in all of these discussions, is what is -- the net metering piece of it is fair compensation for value of the solar. To the extent that that is not a sufficient revenue stream to develop 160 megawatts of renewables which is what the legislature wants to see out of the REG program, then you have an additional incentive on top of that. That's capped at 160 megawatts. That's a defined program here in Rhode

Island. In Massachusetts you have the 1,600 megawatt goal. You have the S-REC program goes only until you hit the 1,600 megawatts. So you've got the net metering piece and then you've got the extra piece on top of that. They're looking at how to do that more efficiently. So it's two components. At some point the incentive will go to zero because, in fact, there won't be any additional value of the solar and, therefore, you won't -- the fair compensation piece won't be enough to cover -- to incent the level of solar or to support the level of solar that really is appropriate in the market.

MR. BIANCO: So this is my final question toward that which is then at some point as we think about this distribution rate, I mean, when we talk about rate stability, does there need to be another standard of rate stability applied to those types of rates if people need to make decisions on a 15-year investment or are we -- should we be looking at this annually and allocating costs that way?

MS. BESSER: So are you talking about looking at rates paid to the distributed generators annually?

MR. BIANCO: Yeah. That's right. So unlike DG, net metering will be exposed to, say, annual rates --

MS. BESSER: Right.

MR. BIANCO: -- as they are now, or six-month rates or even time-of-use rates. On the distribution side, do we need to think about rate stability in calculating the benefits they provide to the system or do we need to be flexible annually and say actually, your system, because a lot of other people put net metering on their roofs --

MS. BESSER: No.

MR. BIANCO: -- you no longer provide the same benefits you did, so actually your rates change.

MS. BESSER: No. If you do that, no one will invest here in Rhode Island. That's the bottom line. If you don't want to see any investment in renewable energy, then you can do ad hoc changes every year. The idea after much deliberation and built into the legislation is that with a 15-to-20-year stream of payments, that it's certain people will invest here in Rhode Island. Companies will build here, and we've seen the success of the 40 megawatt program. But again, that's why it's not an unlimited program. It's a 160 megawatt program and then you can see how successful it is and how -- the value that it's provided to customers. The benefits are -- the projections of the benefits greatly exceed the costs of the program. It's been structured to prevent some of scenario that would lead to paying for things that aren't useful.

I think what I'm sort of hearing maybe underneath your question is that as you think about -- so that's about fair compensation to distributed generation. That's been set by the law. That's not something that we think the Commission here is revisiting, but if you have that compensation mechanism in place and you recognize that those customers are using the distribution system, right now distribution rates are not designed or not well -- or may not be well designed to ensure that the distribution company is compensated for use of the system. And that's what we want to explore here is how do you design the rates so that the distribution company gets compensated for using the distribution grid so it can make the appropriate investments that will enable the DER and reduce the cost of the DER for all customers and not set up weird price signals that would undermine the accomplishments of the DER goals and the energy efficiency goals.

MR. BIANCO: But do you set that up so that it stays -- I mean, you set it up so it's transparent, but then do you set it up so that it moves with the distribution system or that it does not time vary? This is how it's going -- you should expect this type of fixed price for the next five years and --

MS. BESSER: Maybe now I'm understanding your question. The utility's charges for use of the distribution system we expect would be revisited in every rate case that the utility files to see if they're appropriate. If something has caused the utility's costs to go up, then those rates may go up. If something happens to cause them to go down, those rates may go down. So you're not guaranteeing -- is that not --

MR. BIANCO: That's one side of it. And then also the other side is that it's not just the cost to the utility but the benefits provided by the time varying uptake of distributed generation that might affect --

MS. BESSER: Right now I think we have projected in the ceiling prices -- Charity, you can help me out here, are based on a projection of what a certain amount of DG needs to be able to invest and be built here in Rhode Island and there's been a policy decision that that is the way to go and we are not revisiting that. We're not suggesting to revisit that. If something were to happen dramatically in the market that either the prices of DG went up significantly or down significantly, I imagine the legislature would intervene and put something new in place but, again, you've limited this to 160 megawatts. I don't know if the total cost of the program has been projected. It's bounded.

MR. BIANCO: I'm just talking about the distribution rates, not DG ceiling prices, just distribution rates. The distribution rate, the design of a distribution rate that accounts for the benefits of distributed generation resources it occurs to me might be time varying, however, it also occurs to me that investors might not like things that vary with time. What I'm wondering is do you set the rates so that it can vary with time as the benefits and costs of the system vary with time or do you just set it at a rate and forget about it for five years?

MS. BESSER: In Rhode Island the way you structured the incentive program, because the net metering is netted out of the incentive, so if the value of net metering changes here in Rhode Island, say it was -- I don't know, what? $.15, whatever the retail charge was this winter and next winter it's going to be we hope lower because we want retail rates to be lower, it already moves around so there's nothing -- that will happen. I think I'm missing this question.

MR. BIANCO: I think you've got it right there if your idea is that it should move.

MS. BESSER: We're not talking at all about -- in assuring fair compensation to the distribution company for use of the grid we're not suggesting in any way that you're fixing the net metering component within the incentive program, and I think the beauty of the way the Rhode Island incentive program has been designed is that, in fact, the DG company will continue to invest because they have their 15-to-20-year stream of payments and if some of that money comes from net metering and some of it comes from the incentive, they still know the total is X.

MR. LeBEL: I think in general Janet is right, but there are some scenarios, like, say you transitioned transmission and distribution fully to a demand charge that for whatever reason provided zero benefit for the solar, I think you'd want to make a separate adjustment just to reflect some other part of the value. I mean, you can -- there's a lot of different ways you could do it. I don't think in the long run, and I have to look at exactly what the law allows here and we can get into that later. I think in Massachusetts we -- at least we are probably going to suggest having a separate distribution benefit charge and credit system that is not directly tied to the distribution rate, the retail distribution rate. So that is something to consider. You wouldn't want to change it every six months. You could change it every five years, but there are important trade-offs to be made between financability, getting projects built and having that flexibility to get the right costs and benefits over time.

MR. ELMER: I just want to clarify a few things that may have been misstated. The legislature has set the rate for net metering at the sum of the commodity and distribution transmission charge. The legislature has set the compensation under the renewable energy growth program to be determined annually by the DG Board. The DG Board is charged by the legislature with setting that compensation high enough to fill the annual goals in megawatts.

Mr. Bianco, I think you're correct that in the real world because the compensation that is being set by the DG Board every year is substantially higher than what the same person would get for net metering, it is probably rational for a developer to go in for a DG tariff rather than net metering, although I want to point out two things about net metering. One is that net metering is a default under Rhode Island law so that when that 15-year tariff is over, the developer can still default to net metering if she wants. And additionally, as Miss Besser said, there is an upper limit on the renewable energy growth program. So after those full 160 megawatts are spoken for in the tariff, any developer can also net meter and Rhode Island, in contrast to Massachusetts, Rhode Island now does not have a net metering -- an aggregate net metering cap.

Finally, there is a provision in the renewable energy growth program statute that shouldn't be confusing. It is the distribution company's election to account for compensation to somebody who has a renewable energy growth tariff, they can account for part of the compensation under the net metering part as long as they do a trueup in effect and give the full DG tariff to the owner. And I mean, part of the reason that this is important is I think we need to keep in mind that the statutory ambit of this proceeding of 4545 and the follow-on proceeding that's going to be opened on July 1st is setting appropriate compensation for the distribution utility in light of the anticipated growth in distributed generation and/or net metering. I don't think we are properly looking at compensation for the renewable energy developer which has been set by the legislature in the case of net metering and by the legislature through the DG Board in the case of the renewable energy program. That's done. The General Assembly has done that. This proceeding is looking at ensuring, with an E, that the distribution utility is properly compensated for maintaining the distribution system in light of what we expect is going to happen or hope is going to happen, anticipate is going to happen with distributed resources as a consequence of the 2014 statutory enactments.

COMMISSIONER DeSIMONE: I actually probably think this is a good time for -- maybe you need a short break and then we can pick up with the National Grid presentation. We're starting to get a little bit off schedule. I'm sure we can fill in with some questions on all of these topics at the end also.

THE CHAIRPERSON: How long?

COMMISSIONER DeSIMONE: Five minutes.

(RECESS)

THE CHAIRPERSON: So National Grid?

MS. O'BRIEN: Thank you. We have two presentations today. The first one will be Jeanne Lloyd and then Peter Zschokke providing an explanation using a hypothetical example of the impact of different cost recovery methods. I know we specifically are looking at energy efficiency and the ISR plan program. And then there will be a separate presentation that Tim Roughan will provide which is giving an update on the National Grid system reliability demand link pilot update, that pilot program. So I'll turn it over to Jeanne Lloyd and she'll take you through the first presentation.

MS. LLOYD: The first part of this presentation, we're going to attempt to address the specific question or issue that was in the agenda for the meeting which was produce illustrative scenarios that show how two of your existing mechanisms, specifically the energy efficiency program charge and the infrastructure safety and reliability mechanism, allocate costs, do rate design and impact customers in various ways.

So for my part of the presentation that's what I'm going to run through. So the assumptions that we're using in our hypothetical are we're going to recover $10 million annually. And we're not going to worry about what the 10 million represents and whether it appropriately should be through energy efficiency or ISR. It's just 10 million. So this truly is just a mathematical exercise at this point.

So for discussion purposes we're going to talk about does it matter, really, which mechanism that we recover it through. So from a cost perspective, purely cost perspective, either mechanism, energy efficiency or ISR is effective at recovering $10 million in a year. They're both fully reconciling so we can fully recover those costs effectively in either mechanism. However, from a bill impact perspective, which is how it affects individual customers, it does matter.

So why does it matter? Because in each of those mechanisms they're designed differently. Costs are allocated differently to customers and the rates are designed differently so that different types of customers will end up paying different amounts depending on which mechanism we use. So as I said, we flip the -- switch to -- or flip to Slide 6, this really is just a mathematical exercise.

So what we're showing on Slide 6 is a summary of the allocation methods. So the top part of the table we're showing the various allocation factors. And I guess I should stop just to indicate the rate classes, and we discussed those over the various meetings, but just to briefly summarize, the A-16 and 60 is our regular residential and low-income residential class. CO-6 are small commercial customers. G-02, G-32 and G-62 are kind of medium, large and very large respectively. S are our outdoor lighting customers and X-01, there's a single customer in that class. It's for electric propulsion.

So referring to the allocation factors on the left, these are the -- there's actually three of them. There's two mechanisms, energy efficiency and ISR, but within the ISR mechanism we have two types of recovery. So let's talk about energy efficiency first.

Energy efficiency is what we also

refer to as a uniform factor meaning on a per kilowatt hour basis, every customer pays the same on a per unit basis. It's the same rate. That's equivalent to allocating a dollar amount to customers based on their kilowatt hour usage. So that's what I'm demonstrating on the first line which is the percentage of the $10 million that would go to each rate class if it were allocated on the kilowatt hour use of that rate class. Through the ISR factor there's an O&M, operations and maintenance component and there's a capital component. The O&M component which collects veg management, inspection and maintenance costs, that's allocated on an O&M allocation factor. That factor is based on the allocated O&M expenses from our last rate case. The CapEx factor which recovers the capital investment through the plan in each year is allocated on a rate base allocator. Again, that allocator was developed in our last rate case and it was the result of the allocated capital investment and offsets to rate base.

So again, this is just a summary of that $10 million -- of those allocation factors so you can contrast and compare the percentage that would be going to each of the rate classes. So for example, for the residential class, 52.8 percent of the 10 million will go to that class if we use the CapEx factor and 40.8 percent would go to that class if we use the energy efficiency program mechanism.

The middle section is showing the same thing except on a dollar basis. So all I've done is taken the percentages up above, multiplied those by the $10 million and that's the resulting annual revenue that would need to be collected from each of those classes to result in the total $10 million.

The bottom sections are the per unit charges that would be developed in accordance with each of those mechanisms. So as I said before, energy efficiency results in a uniform charge, so it's the same per kilowatt hour charge to every customer. The O&M factor is a per kilowatt hour charge to all classes except the G-62 class. So what we did to develop those charges is we take those allocated dollars that you see in the middle section, we divide it by the total kilowatt hours for each of the rate classes and that results in the individual per kilowatt hour charges that are shown on that line.

MR. ELMER: Why do we not count the G-62?

MS. LLOYD: We count it, it's just that we develop a per kW charge for that class. So you can see that on the line right below, that class would have a charge of $.26 per kW. It's just that particular class has no kilowatt hour component applicable to the distribution charges, so everything in distribution is customer charge or kW.

And finally, the CapEx mechanism for residential, small commercial and outdoor lighting and X-01 we developed a kilowatt hour charge in the same way as we do for the O&M mechanism and then the other three classes we develop per kW charges for those. Those three classes do have a demand component. We measure that and we can bill that on a kW basis.

The next two pages are the bill impacts that would result from implementing each of those charges.

MS. WILSON-FRIAS: Jeanne, can I just interrupt you for one second? Back on Page 6, when we look under the section that says rate design, the -- each of the factors, so either the energy efficiency or the O&M factor or the CapEx factor, is each of those designed to collect the total $10 million?

MS. LLOYD: Yes. Based on the units that are assumed in this example, it would collect 10 million under either or any of the mechanisms.

MS. WILSON-FRIAS: Thank you.

MS. BESSER: Could I ask a clarifying question?

MS. WILSON-FRIAS: Yes.

MS. BESSER: Jeanne, you have for G-2, B/G-32 and B/G-62 under the CapEx factor, you did that as a kilowatt hour charge?

MS. LLOYD: A demand charge.

MS. BESSER: A demand charge. Could you have done that as the kilowatt hour charge? Because they are billed on kilowatt hours, too.

MS. LLOYD: You could have done it as a kilowatt hour charge and we could have done the O&M factor as a kW charge. You can do it either way, actually, because we would have the units available for either.

MS. BESSER: Would it be possible to see what the kilowatt hour charges are for those just for comparison purposes?

MS. LLOYD: I can calculate them. Like I said, I'm using in this example the method that we do -- that we used today which is as provided for in the tariff, so that's why it's presented that way.

MS. BESSER: Okay. Thank you.

MS. LLOYD: You could figure out by

looking how it would compare to the other classes by just looking at the allocated dollars, too.

MS. BESSER: Okay.

MS. LLOYD: If it would be lower or higher. Slides 7 and 8 are the bill impacts. So on Slide 7 what I've done is I've taken a typical customer from each of the rate classes, and the usage for that customer is indicated in the column labeled monthly usage, and then I've applied each of the charges developed on the previous page to that usage amount to show what the dollar increase would be on a monthly basis and the percentage increase. And so then I laid those out in each of the three columns so that you can see the gray shaded boxes, obviously, are the dollar amounts for each month under each of the scenarios. For the three largest classes or the general service classes, G-02, 32 and 62, I actually am using two different customers for each class.

The top line is to represent a low

load factor customer and the bottom line represents a high load factor customer. So what I mean by that is you can see that both of those customers use the same kilowatt hours per month, but each one has a different kW component attached to it. So the low load factor customer has a higher kW billing unit than the high load factor customer does. And that's because that customer is peakier. His load shape tends to -- or he uses more at a single point in time where the high load factor customer tends to use -- his average use tends to be more stable over the billing period. Terry is reminding me that on Slide 19 I actually included an illustration of just what that looks like. So you can see the low load factor customer, his load tends to be, like I said, peaky during the billing period.

The bill impacts or the numbers presented on Slide 8 is really the same thing. It's just sort of doing the math of the impacts that appear on Slide 7. So you can directly see the energy efficiency charge compared to the CapEx charge and the impact of that and then the energy efficiency compared to the ISR. So it's a different way of presenting the information.

So at this point are there any questions about the specific hypothetical that I could answer before we move on?

MS. WILSON-FRIAS: Jeanne, if we take a look on Slide 8 at the G-32 customer, and under energy efficiency, the low load factor customer has a decrease and the high load factor customer has an increase. They use the same amount of kilowatt hours and energy efficiency is a kilowatt hour charge. So why is that?

MS. LLOYD: It's just compared to the other mechanism.

MS. WILSON-FRIAS: Oh, okay.

MS. LLOYD: So if you look on Slide 7, actually, you can see that the increase, if we implemented the energy efficiency charge, would be exactly the same for the high and the low load factor customer on a dollar amount; the percentage would be different for each one.

MS. WILSON-FRIAS: Okay. All right.

MS. LLOYD: If there are no questions about the specific example, we thought because, like I said, that was an exercise of just doing the math and looking at how each of the allocations or the pricing methodologies would allocate cost and then come up with the resulting rate design without any discussion as to what the $10 million was or where it should appropriately be recovered. So we thought it might be useful to take a step back or a step up and talk a little bit more generally about why we pick various allocations -- or various pricing methodologies to recover certain types of costs and look at cost allocation and classification in a more general way. So Peter is going to take over and go through some discussion on that point.

MR. ZSCHOKKE: Good morning, everyone. I'll be starting on Page 10. I won't -- Janet already mentioned Bonbright's principles. I think we already talked about this page. It's really here as a reminder of what has been fairly standard for many decades, what regulators try to accomplish and utilities consider when they make their filings. What are the different things you need to consider while you're designing a rate. It's interesting because you heard an awful lot of discussion earlier about how certain rates will not be accepted by some members of the public and so it's just a real world example of this is the discussion we have, as the Commission is aware, every time we make changes to rates. But these rate attributes are something that are very important.

What we tried to do is talk about the different rate attributes in the context of what Jeanne just showed you so that we could talk about it from the perspective of how do you want to efficiently recover the cost to the utility among customers and how do you want to set prices so that customers can see you make good decisions while using the distribution grid or using the system as a whole.

So on Page 11, just a reminder on the allocation of costs, we obviously classified the costs, demand, energy and customer and direct assignment. If I recall correctly, nearly all of the distributed cost for Narragansett Electric, the distribution company, are allocated to the rate classes based upon demand -- the maximum demands or the number of customers or a direct assignment. For example, in a cost of service, an allocated cost of service, the cost streetlights are directly assigned to the streetlight class. An interconnection issue, the cost for the interconnection is allocated directly to the customer requesting the interconnection for a generator or through our contributions in aid of construction tariffs for customers who are coming -- who are going to be a load customer based upon historical precedents.

These obviously create allocation

factors that Jeanne has just described to you, and as you saw on those pages which we will return to in a few slides, there is a difference between the energy and the demand charges and that makes sense. And it all has to do with load factor and the efficient use of the system. And then, of course, those allocation factors are determined, as Jeanne showed, how much money is collected for specific types of costs through each rate class.

So I wanted to talk about a couple of the Bonbright principles. So recovery and stability of the revenue requirements. So the rates have to be designed to allow for adequate opportunity to recover the revenue requirement and obviously stability over time both for customers and their decisions, as was discussed earlier, as well as for the utility to understand the revenue flow going forward. And part of that is the effectiveness of yielding the total revenue requirement. How effective would we be able to yield the total revenue requirement, particularly in these changing environments that we are faced with now.

So the implications, for example, when I think about recovering capital investment through the energy efficiency program, simply put, the energy efficiency programs have really been something we use to fund decisions by the customers to be more efficient in their use of electricity. So the idea that we would actually fund company investments through that raises an interesting question on the use of those funds to start with. But also, when I think about it, you're going to fund a capital investment and then some questions come up which is how are you going to pay for the ongoing O&M costs associated with that investment? If you fund it upfront through EE, there's nothing in rates that provides any revenue that would, No. 1, obviously amortize the investment but also provide additional revenues so you have monies available for additional O&M that comes on, all equipment that comes on the system, including the investment made, but also what about replacement? So when you go to replace it, whether it's after a storm, there's damage or it's no longer operating effectively or it's been damaged and has to be replaced in order to provide reliable service, when you replace it, there's no revenue in the company's revenue stream from customers that help with the cost of that replacement. So that replacement comes as a direct additional cost which may or may not contribute to the need for further increases in rates by the utility.

So there's the use of energy efficiency funds to directly pay for something like volt/VAR optimization which are what some people in the industry suggest creates other issues, and those issues are going forward for the utility. We have some of those issues with, obviously, the costs that we've recovered through CIAC payments or interconnection payments. We don't have any ongoing revenue that actually stabilizes the company's revenue requirement and need for operational and investment cash to maintain the grid going forward in system.

MS. WILSON-FRIAS: So Peter, so what -- since you brought up volt/VAR --

MR. ZSCHOKKE: Volt/VAR more than --

MS. WILSON-FRIAS: And it's come up. So what if you funded -- what if you funded the capital through, say, an ISR, but then there's ongoing O&M expenses, and let's assume they can pass the total resource cost test, whatever benefits are found to accrue from -- as a result of volt/VAR, would that be -- do you think that might be an appropriate recovery mechanism through the energy efficiency in that specific instance?

MR. ZSCHOKKE: I would say that comes down to the efficiency of rate cases and -- because once you get into the O&M side, you've got specific charges and other things are happening and then the company has got to strip out these small elements of costs that are funded through EE or through general rates, so it becomes a question of the efficiency of the rate cases. And again, it also becomes a question what are you using the EE funds for? What's its purpose? People need to keep in mind -- everybody jumps on the idea that volt/VAR will help manage voltage on the system, and therefore, possibly reduce customers' usage by lowering the voltage, and that can happen.

The -- but really, when the engineers talk about it, when I go to talk to the company that we're working with down the street here -- actually, up the street because it's in Providence, they talk about the efficiency -- efficient operation of the elements of the grid that we've built. So by managing the voltage more actively, they're able to lower, for example, the operations of other pieces of equipment on the system. So -- because they have a better vision of what's happening on the grid and they can manage it much better. Lowering the number of operations increases the life of the units and reduces any damage that may happen from any operations that may occur because there's too much voltage or too small voltage. Because really, when engineers look at -- and I'm not an engineer, but I've hung around with a lot throughout my career, the number of events contribute to the life of -- or lowering the life of the assets in service. The more events they have to deal with in terms of things that happen on the system, the greater the chance you're going to lower the length of time you can keep that unit in service. So by minimizing the operational events on the system, you are actually contributing to the greater value of the assets in service and a longer life span that you can have. So there's more than simply managing the voltage that goes on. There's a lot of operational benefits that occur as well.

MS. WILSON-FRIAS: But if the goal is to look at all programs and state policies as a whole, system reliability and least cost procurement and energy efficiency are not all just one -- like, it's not like a tree with five branches. They're all supposed to work together, and in fact, I believe it's least cost procurement references the standard offer statute. So I guess at the very beginning when we started these considerations the issue was how do we look at everything together. And so where there is a piece that something might contribute, because when you do research on volt/VAR, you see that there's -- a lot of the companies that offer this and other Public Utility Commissions have used this as an energy efficiency mechanism and it's advertised as such. So I guess it's sort of the most obvious thing that is out there right now that you're doing that seems like it spans several different arenas and all of those pieces. So that's kind of why I keep asking question over and over again.

MR. ZSCHOKKE: Well, you can certainly fund it through the energy efficiency fund. The question is what is the goal of the energy efficiency funds? So that's the real debate that has to happen. But you have to keep in mind what's the ongoing run the business costs for it if you're going to fund it that way. And then the other element is replacement costs. So -- and that's a debate -- unlike energy efficiency where if you pay somebody a rebate for a refrigerator and then you go on to the next refrigerator, the -- this will have ongoing costs, so that will take up a bigger chunk of the budget every year as you do more and more of the volt/VAR.

So that's something that has to be considered because the energy efficiency funds are simply another source of funds from customers to pay for the cost of the utility if you want to look at it that way. And that's going to have, obviously, an interesting debate at the EERMC when they discuss it, using it, but you certainly could consider it. You just have to understand what the effects are going to be long term to the use of the energy efficiency funds that are collected from customers in Rhode Island.

MS. WILSON-FRIAS: So should the different programs, like energy efficiency program or system reliability, should all of these things be looking at what's in other parts of the rates or other programs or other cost recovery factors, for example? So let's say you leave volt/VAR where it is and you don't do anything in energy efficiency, but it does have an energy efficiency benefit. Should the cost and the benefit related to volt/VAR outside of energy efficiency be worked into the energy efficiency analysis at all, or vice versa when -- if the goal is to look at how all policies are working in all rates and programs?

MR. ZSCHOKKE: You can certainly consider volt/VAR in conjunction with all of the other energy efficiency elements, programs that are going on and evaluate what's the best way to manage them all together. There is a difference with, obviously, the example that we presented, how energy efficiency is applied across rate classes versus how we build our system. So volt/VAR does provide energy efficiency benefits, but we build our system to meet MVA peaks, really, and we manage that system in order to reduce events that may cause problems. So the question is are you going to allocate the specific costs differently through the energy efficiency factor than you would any other energy efficiency costs, or how are you going to reflect the system efficiency element which is we want customers to understand that the maximum demand is what's planned for on the distribution feeders and substations and how do we factor that into pricing going forward?

You heard earlier from Mark I think about demand charges. I know battery manufacturers want demand charges because -- and we think demand charges are the correct way to go if you're pricing on size for all customers. It's a question of whether or not we want to spend the money on the meters because that really teaches -- it makes customers focus on really what they are causing on the system. Their maximum demand makes the system require more capacity. You probably have heard at ISO New England presentations or seen on the website, the load factor, i.e., the ratio of average usage versus the maximum usage in New England have been falling for a long time which means we're putting in a lot of capacity to serve fewer and fewer kilowatt hours. So we have a struggle right now in New England to make the system more efficient, and partly that's because we are pricing a lot of the bill on energy and customers aren't seeing that signal to manage their demand in such a way that it is more efficient for what is necessary to build the system, which should be a focus, I think, for the future if you want the system to be as efficient as possible.

MS. WILSON-FRIAS: But I mean, energy efficiency programs are funded through the demand side management charge.

So I mean -- is part of the energy efficiency supposed to be to address demand?

MR. ZSCHOKKE: Yes. That would be a second reference to Back to the Future, because that's how they started.

MS. WILSON-FRIAS: And to try to address that peaking issue through those programs as well.

MR. ZSCHOKKE: We would encourage that, yes.

MR. NEWBERGER: We have goals. This year the company's goals for energy efficiency include a demand component, so not just energy -- this is the first year in -- at least in my memory, that we've adopted a kW goal as well as a kWh goal.

MR. BIANCO: But just to -- and we've talked about -- I've talked to probably a lot of you about this, but the charge itself, right, the Commission's ability to indicate to ratepayers perhaps rates that might incentivize or put a greater cost on behavior, isn't cost allocation and how we charge rates and we don't have a demand charge for energy efficiency. It's a per kilowatt hour, right? So someone who is efficiently lowering their demand but has no demand charge and does not pay an energy efficiency portion in demand really would not have any benefit to any of the -- anything they might do to lower their demand, and that describes residential ratepayers, right? They pay per kilowatt hour on both distribution and energy rates and they pay per kilowatt hour on energy efficiency, so they know nothing of demand, for example.

And if you were a renewable energy customer, one might say, yeah, we should -- we want you to point your solar panels west and we'll give you an extra incentive to do that, but you might also just have a demand charge such that those customers would naturally have reason to point their solar panels west because that's when they would have the opportunity to lower their demand cost. So while you have an incentive to meet demand goals, there's nothing for ratepayers, particularly residential, to meet demand.

MR. NEWBERGER: There are several technologies that -- for which energy efficiency incentives are offered that have different load profiles. We offer incentives for high efficiency air conditioning. So we know that, that customers who would accept and adopt those technologies will be reducing, will have a greater impact on demand savings than they will -- for somebody who -- compared to somebody who adopts a different technology. So we use the mechanisms that we have available to us for offering incentives to drive customers to technologies that work for them, but also provide both energy and demand savings.

MR. BIANCO: But as an individual ratepayer -- I want to just see if you agree. If I were putting a solar panel on my roof or getting technology in my house to reduce my energy, as a residential ratepayer, total kilowatt hours is all I care about. I personally in my house receive no benefit for anything demand. Now, there's a benefit that accrues to me that I'll never notice on my bill perhaps, that accrues to all ratepayers like a decrease in distribution costs, things like that, but when I said, "Hey, I did this installation," or, "I got an efficient refrigerator. I have south facing versus west facing solar panels," that's all energy for me because that's all my bill is charged on.

MR. NEWBERGER: That's correct.

MR. ZSCHOKKE: And if you actually turn to Page 14 which is a repeat of a slide Jeanne spoke about, so when you go to the Narragansett Electric cost of service, you look at distribution costs, you'll see that demand allocation, residential gets 53 percent of the costs but they're only 41 percent of the kilowatt hours delivered. What that means is we now need to charge them a higher per kilowatt hour cost to reflect -- to collect the demand portion of the bill, which means the cost per kilowatt hour is higher so there's more incentive to actually save on those kilowatt hours and we're not reflecting that high use of the demand system which is where we want to save the money. And that's one of the -- a number of Bonbright's principles factor into that. How do you encourage the right -- how do you encourage the right decisions on the part of the customers to make the system most efficient? How do you create rate design that yields revenue for the company and makes the system more efficient, therefore, the company has to spend less money? And that is something that has been standard in the industry using demand based rates to encourage customers, and Tim and I both know, Tim more than I, that back in our demand rate days, customers made a lot of decisions based upon the demand rates we charged and those who had them, they worked to save money on those. They really took focus on that stuff. And in the advent of solar and battery storage and electric vehicles and more and more central air conditioning coming on the grid, managing those demands is really key to getting the most efficient systems you can get.

MR. BIANCO: I agree. It seems that you reach a limit. At some point an individual user has a certain amount of energy they need to use in a month and there's no -- I mean, further efficiency gains is just austerity, whereas, there's a lot of room in demand and when I make these choices that the current system doesn't really allow for those benefits to move back and forth.

MR. ZSCHOKKE: I was at a conference yesterday and the person who -- was talking about Texas, but Texas has a benefit that we don't have in New England which is -- well, we have a benefit Texas doesn't have. Let me put it that way. We have four seasons, right? So I had neighbors who came to Massachusetts from Texas and they love their electric bill because their electric bill is $1,000 less than what they paid in Texas because they're all electric heat, they're all electric air conditioning and they're using it every single month of the year. Granted, they have a heating bill, but they were just loving their electric bill and they thought they had found lots of money. And most people don't understand that when you talk about cost per kilowatt hour, the load factor, the efficient use of the system, oh, if I had 10 to 12 months of air conditioning or electric heat, you know, going constantly, that contributes to a pretty high load factor. So -- which contributes to lower cost per kilowatt hour for generally a fixed cost system. And that's why, although people don't like to use the term Arizona, but Arizona and New Mexico have both contemplated and used demand charges for their residential customers because of the massive amount of air conditioning that is required to live there. They've actually implemented those for years because they want customers to manage their demands in such a way that they're using it off-peak, they're pre-cooling, they're being as efficient as possible because of the needs of building out the grid. So those are stated mechanisms.

The real question up here, obviously, is the cost of the metrology to, obviously, implement that. It's very expensive to implement either AMR meters or demand based meters on an AMR basis, more expensive than it would be just to use an energy year. And the question is what would be that value to do so going forward is one we can obviously study. Obviously, our proposal that we talked about here before is what Janet mentioned earlier is a tiered customer charge to reflect the size of the customers on the -- that are on the energy only rate so that you can kind of work into a demand charge going forward, but also fairly allocate the cost of the distribution grid. Those who are bigger should pay more than those who are small.

So let me just return to Slide 13

which just goes through fairness and equity. We talked a lot about that, and that's really the primary cost drivers. We work through the cost of service and the allocated cost of service to really reflect who -- what classes are responsible for the costs and should be paying for those costs in a fair and equitable manner as determined by the Commission based upon the evidence in the case.

And of course, no undue discrimination. We really don't want to treat somebody with solar different from somebody who doesn't have solar. The reality is if you have a certain size facility, you have a certain capability of using the grid either by delivering solar back out to the grid -- generation back out to the grid or by consuming within the grid, and that's what the system is going to have to contemplate building going forward.

I spoke about Slide 14. So I'll move to efficiency and rate attributes. So again, we talked about rates needing to be designed to yield total revenue requirements. Price signals. I've inferred it, but obviously, we talked about we want the prices to reflect the marginal costs -- the incremental costs to serve the customers. We want to pay customers for the value for that incremental cost if they're providing the service to us. And we should be moving forward as a state considering how we advance rate design to create these efficiencies and to create these signals such that customers can make good decisions that help them manage their loads in such a way that we can improve the load factor of the system and lower overall costs to customers.

At the same time we have to be mindful that they have to be simple and easy to understand. One of the fundamentals of Bonbright's principles, the question is how far do you go? How soon and what technology do you have available to allow you to go that far? And then what's the process for getting customer acceptance of those rates?

How do you educate customers? How do you talk to customers? How do you explain why it's more appropriate to do this? And really, I always look at it as explaining to them what's the opportunity for them? What's the value for them? If they can save on their demand, they manage their demand to keep it as flat as possible, they win, right?

I'm going to be talking to an EV charging company tomorrow and they happen to not like demand rates, but they don't like demand rates because right now they have very few cars charging at their stations, but when they get a lot of cars charging and they're being paid, charged an energy rate, they're not going to like it because once they establish their peak demand, every charge is free from a distribution perspective. But if I'm charging them on an energy basis, everybody who charges is a cost. So we'll have an interesting discussion.

The other issue is gradualism. I

mean, simple and easy to understand and gradualism are important concepts because what it means is it's hard to change rates. It takes a lot of work through the regulatory process because once a rate is established, nobody wants to give it up because they figured out an advantage to it. So when you change it you have to figure out how you can change it in such a way that customers still see some of their value or see a better value and can come to the table and accept the change. That's a real -- that will be something that -- that's something that all Commissions and this Commission struggles with every time there's a rate case or some rate increase that happens to customers.

We just put back in the -- this is the same chart, but just looking at energy versus demand versus customer. The impacts that customers would have on their bills for the same $10 million cost and Jeanne showed you how she came up with the factors, and so you can see what the difference is. If I go to a customer allocation, the large customers see very little impact. But the small customers see a really big impact, and you heard Mark discussing that same issue today. Whereas, if I go to an energy, you see the impacts you saw earlier or a demand, again, you see the same impacts, but you'll notice that the demand impact is -- has, I would say, a more narrower band relative -- of percentage changes than the other ones with the exception of the high load factor customer for the G-62 and also the high load factor for G-32. But that makes sense. If you're a high load factor customer and you use -- and what we're concerned about is what your maximum is on the system, you should get that benefit because you've managed your demand, you flattened your load curve as much as possible. I don't think we have any air separation plants in New England anymore, do we?

MR. ROUGHAN: No.

MR. ZSCHOKKE: So when we went to restructuring we went to a lot of energy charges, and air separation plants actually have a 95 percent load factor, but they're also very mobile. There's only a couple of employees in the plant and they -- their facilities can be moved and they've all moved out of New England because -- and they serve hospitals. They provide the air -- components of the air at the hospitals. And they moved out because they want the demand charge, right? So battery storage companies want the demand charge. Because somebody with solar on their roof from behind the meter is not going to buy batteries if they're focussed on energy because there's no -- in some months some our customers eliminate all their energy use. There's no consideration of what they use in the system. Whereas if there's a demand charge, well, now the battery storage manufacturer now says, "Well, I have a business model that can work," because now a customer has an impact from their size on the system.

So we've had actually battery storage manufacturers, inventors actually file comments in Massachusetts at least on the grid mod saying, please give us a demand charge because it will help our business model. From our perspective, that helps manage the system. It provides a value that Mark and Abigail were talking about and Janet were talking about to the grid by allowing us to manage generation output on the grid level with battery storage so that people can flatten their load curve or create benefits at the time when we need the loads to fall on the system by having that run through capability with the battery storage.

MR. BIANCO: So they imagine similar benefits -- could they achieve the same type of -- the business model may be a little bit different, but could you achieve the same value in battery storage with just time varying rates on a kilowatt hour collections and payments, but just totally time varying rather than going through the trouble? So you still need new metering, but perhaps a different type of meter.

MR. ZSCHOKKE: Well, it depends on how the time varying rate is designed. If there's not much delta, no. But the problem we have in New England is we don't have a market that allows you to do time varying rates really well because the forward capacity market is based -- you charge based upon your peak demand at the time of peak last year, the 12 months, and so it's not a realtime market for capacity and that's really the driver for battery storage. How do you -- you want that demand charge to be incurred at the time you need it.

So for our smart energy solutions pilot in Massachusetts we have a -- I don't know 55, $.65 per kilowatt hour peak charge for 175 hours in the summertime. It will be interesting what happens this summer when we first start charging customers those prices. But theoretically, that would work, however, we're collecting all those -- we're breaking down the basic service price which we get on a monthly basis or a periodic basis as a flat price for all kilowatt hours sold under basic service and putting a lot of that value into these few hours. And the problem from a regulatory perspective is the inner temporal covering the cost. So I'll be paying $.10 a kilowatt hour for service in the first six months of the year, but I'm going to be charging customers on smart energy solutions less than that because I've bundled all this money into the 175 hours, primarily because the wholesale market doesn't work that way. Even though that's what the FCM is trying to show. And so there's obviously this issue with how do you promote those types of rates when the wholesale market isn't necessarily convenient to cost recovery mechanisms that are coincident with when the costs are incurred. Something I'm worried about this summer, but we'll have a great example after the summer.

MR. BIANCO: Is any of that program part of a -- I'm just wondering, did you bid in for demand response, active demand response? Is any of the money recovered in the FCM through demand response as a capacity, an asset?

MR. ZSCHOKKE: So smart energy solutions is a pilot, so we haven't called the prices yet. We will this summer when we're finally up and ready. We've done some demand bidding before, but I'm not familiar with it. Tim is more familiar than I am.

MR. ROUGHAN: Well, we've got the efficiency that Jeramy's team bids in every year that flows back, those values flow back to customers and help fund those efficiency programs, but because of -- the pilot is so short in Massachusetts and the challenge is when you bid in capacity in auction in the winter of a particular year, the capacity isn't required to be delivered for three more years, so when you've only got a two-or-three-year pilot, you bid in five kilowatts but then you can't deliver it until year three, so that's why we didn't in that particular case. But for the solar projects that we own in Massachusetts, we did put those into the capacity market and we do get some revenues for those to help offset those costs to customers.

MR. ZSCHOKKE: I think the other issue why we wouldn't bid in is we want to see how customers will respond and how much we're going to get. A minor issue, but an important one. That's all I have. So any questions?

MR. ELMER: I don't want to go too far afield here, but under the re-design of the auction with the pay per performance, how do you account for when you're only looking at 175 hours in the year? If you acquire a CSO after the auction --

MR. ROUGHAN: We didn't acquire it.

MR. ELMER: Thank you.

MR. ZSCHOKKE: We need to see if the 175 hours works with the -- we actually have a lot of customers still on the smart rewards pricing which is the pricing element, but it's an opt out program, that's why they're on it. So we're going to learn a lot over the next two years and we can have a better discussion in two years.

MR. BIANCO: I did have one about costs and benefits. If there was a reduction in demand, it's not like you go out and say let me get a lower rated wire now because that guy's demand went down. You leave that wire in place. There's a delay in time before benefits, maybe not in O&M, but there's a delay in time, in capital investments, for example, right, similar to how energy efficiency works? Some of the benefits will accrue over 10 or 15 years. So you have to -- I guess I wanted to understand a little bit about that. How do the benefits of, say, volt/VAR accrue? It's not right away, or do you have a method -- is there a method of figuring out over time how it accrues?

MR. ZSCHOKKE: Well, volt/VAR has --

MR. BIANCO: As an example.

MR. ZSCHOKKE: Volt/VAR could have an immediate benefit. It depends on where you set the voltage. Energy efficiency for some or all customers on the feeder, depending upon what level of voltage you set it at and what circumstances were before. So that can be immediate. The demand elements -- so just for the record, all utilities work on standards so they can buy equipment efficiently. So we're moving from four kV service feeders to 13v kV because you can handle more load, you can have more flexibility and you can handle more DG on the system. And so we're not going to go from a 13 kV line to 11.5, right? That's not going to happen.

However, every line -- engineers like to have a little bit of flexibility so that when they're going through their planning studies, if the lines are interconnected such that they can make them interconnected, they can actually -- instead of investing in new feeders to serve customers that are lightly loaded, they can actually move load around by reconfiguring where the starts and stops are on the different lines. I'll call them that in my non-engineering way. But they'll actually have an ability to balance either in emergency conditions or when they're thinking of what's the least cost way to actually serve the load that's coming forward, they can actually think about moving loads among different feeders in a way to address those new loads. So having additional capacity provides them an ability to provide lower cost service over time by being able to shift loads for a given level of capacity in the system. Eventually, though, if load does grow or demand does grow, you eventually have an issue where you'll have to invest or if there's a contingency issue they're trying to address, that's another reason for investment.

MR. BIANCO: With energy efficiency, though, a light bulb, that light bulb is able to save a certain amount of energy and then the assumption would be that it does every year even though you have to factor in customers' use, that that customer just might have stopped using that room with that light bulb. And actually, so that energy isn't saved. The ten kilowatt hours a year that they might have used and now they're saving five but maybe they don't use that room anymore, so they really didn't save that five.

What I'm wondering is -- do you have to a create a baseline projection of what the grid would require a number of years out to get an understanding of what the benefits are of demand reduction?

MR. ZSCHOKKE: Well, energy efficiency is like salt. This is one of our planning examples. If you sprinkle it all around the system and over time you created all these benefits from having salt sprinkled all over the system. And kind of built into the planning process because we assume -- it's reflected in the load growth we see because homes are more efficient today than they were in 1990, the appliances available are more efficient when you build a new home, when you buy a new home and you put in new appliances. So it's really built into the planning process based upon how we have addressed energy efficiency over time. So those are words straight from one of our smartest distribution engineers. And that works and has worked to save money on the distribution investment system. What we're trying in Tiverton, which we'll talk about after lunch, is, obviously, really focussing in on energy efficiency and specific technologies to see if we can address a specific area. And -- which is a different concept than the salt concept, sprinkling it all over the place. And so those are kind of two elements.

So we've had the benefits. They are built into the planning process through the load demand forecast and the impact that energy efficiency has had on the load demand including the fact that some customers put in a light bulb and maybe they're not using the light bulb right now because that's all part of the usage, part of the forecast, so it's all built into that.

MR. ROUGHAN: Maybe, Todd, to your point, a demand charge construct would provide the same sprinkling of the salt all over. So just like efficiency. When that light bulb goes in there that he saves ten kilowatt hours, it's also a 13 watt bulb, not a 60 watt bulb, so it's a reduction of 47 watts. It's a peak load reduction. So that's a key component of efficiency. But similar to salt being sprinkled around, demand charges would have the same effect, and over time, that's where the benefits would accrue.

MR. ELMER: Just to acknowledge that -- I may not be smart enough to understand the salt metaphor, but there is a distinction or a possible distinction at the ISO system level where the ISO's accounting for energy efficiency generally gets accounted for and is embedded in their forward looking ten-year load forecast. On the DG side there is at least a nascent controversy as to the extent to which DG does or does not get accounted for as being already embedded in the load in the forward looking forecast. So that in this proceeding here where we're talking about the effect of distributed generation on the system and appropriate compensation for the distribution utility, the analogy with energy efficiency may not be fully applicable. Energy efficiency gets embedded in load forecasts in a more comprehensive way than DG gets embedded in the ISO's load forecasts. It's just a distinction that's worth keeping in mind.

MR. ROUGHAN: Well, I think there is no question there is a difference, however, most of the load forecasts the ISO is also doing comes from our transmission planning folks and every utility's transmission planning groups. And if, just like efficiency, the peaks loads in the area are growing slower over time and that see the meter data, that's incorporated into ISO load forecast. And they do also include the future forecasts of what folks predict for efficiency, you're correct, but there is going to be some of that that will also occur from DG as the peak loads are modified because DG is running at peak, but not to the extent of efficiency, I will grant you that.

MR. ELMER: And that's an important distinction because 80 percent of it -- if it's $1.1 billion now being spent in the six ISO states on energy efficiency and 80 percent of that cleared in the forward capacity auction, whereas much of the DG is not reflected -- it doesn't play in the auction, it doesn't clear in the auction and it's not embedded in the load forecasts that are done. And I'm just acknowledging that that's a distinction between the energy efficiency side and the DG side that may be worth keeping in mind as we think about a revenue neutral rate design proceeding.

MR. ZSCHOKKE: So something we want to analyze in our smart energy solutions pilot is what does demand reduction mean? What is the value you get? Because I've seen the load duration curves. I've seen the peak load curves. I understand what's happening on the system at the ISO on the peak days.

Traditionally, if you go back to the '80s, people say, and I think I mentioned this before, loads in the summer were very spiky in New England. Now they're just a big hump. So one of the things we want to analyze is if you get a megawatt of demand reduction or whatever, is it really a megawatt or is it less than a megawatt because you actually have done something somewhere else on the system or at some other time that is contributing. And I think that may -- with energy efficiency there's obviously a lot more history that we have in terms -- because we've been doing the programs for 25 plus years. So there's an awful lot of history that the ISO can rely on and be more certain of. I think there's going to be an issue with demand response and with distributed generation just understanding what is contributing to the actual peak that I have to plan for. Because of the, A, the load shape of the generation output, particularly the solar, but also the impact of what may possibly be clouds.

MR. ELMER: Not to put too fine a point on it, Peter, it's not going to be an issue, it is an issue now because on January 2nd FERC issued an order directing the ISO to use its -- at least some components of its DG forecast in calculating its installed capacity requirement for FCA 10, and the manner in which the ISO is or is not doing that is subject to some controversy now.

MR. NEWBERGER: Just to your point, not commenting on the recent FERC order, but even before, if there is DG that appears that the ISO did not include in its forecast, there is as lag. They eventually do catch up with it because of the forward capacity market. They'll catch up with it in three or four years.

MR. ELMER: Of course.

MR. NEWBERGER: So there are already mechanisms -- though there is a lag, there are already mechanisms in place for how they do account for DG in their load forecast and in the ICR calculation.

MR. ELMER: Yeah, it's eventually reflected in load, but the issue is that the FCM is based on a future -- three-year future looking load forecast. Inevitably, it all gets reflected in load, but the auction is a forward auction and that's the etiology of the controversy.

MR. NEWBERGER: And even when the DG is installed, it's not just for that one year, it is -- it will be there for a long time. So sometimes we look at it and say it's missing out on the first three years of properly reflecting the value, but over the full life of it, there's a lot of value that is properly captured.

MR. ZSCHOKKE: And I do want to compare and contrast what the ISO worries about versus what our distribution engineers worry about because their issue is you're putting voltage into a system that never received voltage except from the substations, right? So their issue is I'm now going to get voltage from all these different points on the grid. How do I manage it and manage voltage to other customers so that they have service that's reliable, safe and doesn't damage their homes and businesses? So that's their real issue. That's why you heard some statements from Janet earlier about limitations on the amount that a feeder can take because they've never had to do that before, so it's a big issue for them. And it's a big issue for the industry in terms of well, how do you engage solar? How do you bring it in? How do you use solar to benefit the grid, but actually how do you manage it? What are you going to need to build? It's a very interesting question for the engineers. And I specifically use the term voltage because I read a lot of sanction papers from the engineers. The only time they talk about megawatt hours is when they talk about the number of hours of outage that may be occurring because we lost a transformer or something. They really talk about MVA and that's how they build the system and plan the system.

COMMISSIONER DeSIMONE: It looks like now is a good time for the break and we'll be back in what, 45 minutes? Everybody is that good?

MS. GOLD: 1:15.

COMMISSIONER DeSIMONE: 1:15.

(LUNCHEON RECESS)

AFTERNOON SESSION

JUNE 14, 2015

1:30 P.M.

THE CHAIRPERSON: Okay. Are we ready to get underway?

MS. WILSON-FRIAS: Yes, Chairperson. I think we're on to National Grid's demand link pilot update presentation.

MR. ROUGHAN: Good afternoon, everyone. I hope everyone had a good lunch. We did. So we're going to go through the system reliability procurement plan update which really is our demand link pilot and get into those details in a second here, but hopefully everyone has their presentation. If you don't, maybe we've got an extra or two. Okay.

So jump into the first one, just some basics here. A lot of this a number of the folks in the room have seen already, so I might go a little fast, but can always respond to questions. So non-wires alternatives. The first slide really is leveraging customer-side resources to try to maximize the efficiency of the distribution delivery system and/or transmission delivery system depending on how extensive that is. With the kind of monies our customers are paying for energy efficiency, subsidies for DG and all the rest of it, it only makes sense to try to leverage some of those costs to see if we can do something about our transmission and distribution expense. So that's really, again, using those to provide capacity value to the system so we can at a minimum defer a plant expansion and, depending on how things go in the future, potentially actually not to have to build it at all.

So again, there's a lot of reasons we pursue these. Slide 3. A lot of folks are interested. I think I want to mention about leveraging customer money I think is a critical point here that we all have to think about here. One of things this also provides from National Grid's perspective at a minimum is also the need to -- as we try to manage and use customer resources, it really calls for what -- to modernize the grid, to be able to see things in realtime and really be able manage that customer load in ways that we've never done before. So that's really going to be important going forward for ourselves and for our customers.

No. 4 is really -- we've been working on this for quite a while. We started kind of having some conversations with our planning engineering teams both on the distribution side and transmission side to understand better how to try to use those customer resources in their planning process.

So way back in 2011, which it took a couple years to pull through, we did come up with an internal document that helps our planning folks understand where we want to look at non-wires alternatives. We do have four criteria that we look at because non-wires alternative being customer-side resources can take time to plan; lots of issues around that. So in the green box to the left you'll see that the needs really are that in order to have enough money, the deferral value is anywhere from six to ten percent of the initial cost of some sort of upgrade. So in order to have enough money to incent customers to do things, one of the criteria we look at is is it a million dollar upgrade or not. That's the first criteria. Second is it can't be related to an asset condition. You can't be looking to defer replacing a 52-year-old switch that we can't get parts for. That's not just something that we're looking at. So that location, if it's asset condition, is not going to be considered.

It needs some lead time. In this case we're talking about three years or more so we can kind of get the project up and running to try to meet the load needs when we expect the load to occur out there. And ultimately, we also can't expect to reduce the load by huge percentages. So we are looking -- we're only looking for approximately 20 percent or so of the peak load of the need in terms of what we look to get resources from the customer side in terms of that peak load reduction.

Going to the right side, once the engineers have kind of looked at their planning and we then go through and look at in a specific location who are the customers in that footprint. What kind of customers are there? What's driving the peak load conditions we're seeing, and what sort of technologies are we aware of that we think we might be able to help customers install, put in place that could provide this capacity reduction at the times we need it for the duration we need it, because when we look about deferring any investment, there are some years where we have peak conditions on the system, other years we don't. Last summer was a good year where it was a nice summer, cool, really had no true, hot, humid heat waves that caused significant peaks and it was reflected at the ISO level and at the our local distribution level. But some years, I've been in this business a while.

2002 was a hugely hot year, 2010. So we have to be -- this is insurance, if you will, this non-wires if we can't have the actual conductor in the air or transformers on the ground. So when you look at the interval to manage the load from a customer-side resource, you need to look at how many hours of summer you might need them. Is it two or three or four days in a row? Is it only one hour a day? Is it four or five hours a day? And how many years will you need it? Because the whole premise once you put conductor in the air, it's going to provide capacity for the expected life of that conductor, 20, 30 years. Whereas customer-side resources, it's a constant refresh, if you will, with that customer base to make sure that they're still available, because right now we're still at the early stages of any sort of automation of customer loads and so a lot of things that are done now are still very manual by customers, but we'll get into some of the automation which we do have in the pilot in terms of how we expect that to move forward.

The background here is basically the original least cost procurement law. I'll get into Slide 5. Under that there was a lot of different things folks are aware of but one of the key things is the system reliability procurement plan and out of that is where the whole non-wires proposals are out there. There's a plan we file every three years and then we have an annual update to that plan, but every three years there's a refresh of the larger plan and we've done that twice, '08 and '11, and we'll be due for another update -- oh, actually, we just did one last fall, right? Counting three plus three plus three.

So getting to Slide 6, the standards are out there, and if I add right, just like this, the minor update was in 2014. We talked about the different aspects of the non-wires and also the different types of reporting requirements around them. So these were filed every year in terms of the projects.

So there's two things we do in our SRP, system reliability plan reports. First is show all the projects that we are looking at from a planning perspective and whether they did or didn't make it through the non-wires filter, as I mentioned, those four criteria. Most don't, frankly, because there's asset conditions -- and you have to remember, projects that make it into the ISR have to have a number of factors that make it so they pass, if you will. So it's very rare you have a project that's only for reliability or only for growth. Typically, projects have -- do all those things, grow, reliability, asset replacement so you have all the values when you do upgrade the system. But in those cases where you've got a relatively recent upgrade that you've done in the last five to ten but the load growth is exceeding what you expected the load growth to be and you're looking at upgrading that system sooner than you normally would have, that's where you're looking for the non-wires.

Typically, the assets are still in very good condition. Typically, reliability is still very high. So it's simply a growth-related thing that we have to do when we have to just manage and lop off those peaks to get more life out of the existing plant.

So they have their own dockets here. We meet with the efficiency world. We're close with the EERMC as well in terms of the system reliability plan, and as much as we can we also try to leverage as much of the efficiency dollars as we can because customer-side resources aren't just DG or demand response. They are indeed energy efficiency, and in this case for this pilot targeted energy efficiency and so we try to leverage the money we're already collecting from customers through efficiency. And so when we ask for any sort of funding for SRP, it's simply in addition to what we already would have been getting from energy efficiency and in all the years so far, if

I'm not mistaken, we've been able to use almost half, if not more than half, of the total SRP budget comes from the efficiency programs already approved so we don't have to ask for this much, the total amount, and we only ask for about 48 or 50 percent of the cost.

So getting to Slide 8 specifically, Little Compton and the southern portion of Tiverton are the locations. Due to reliability or contingency issues, the two feeders that serve the area, neither feeder can feed the whole area if you lose one or the other and they essentially back each other up because they're down in that peninsula area. So the third feeder was proposed so you had that backup if you loss one of the two feeders. But again, that third feeder was only needed if the outage occurred during peak. If it occurred today, for example, either circuit could still handle the whole load, but on a nice hot July afternoon, that's when the third feeder would kick in.

So we went through and with the engineers helping us understand how many kilowatts of load relief needed by year and how many hours a year based on planning estimates we came up with this particular project. And the third feeder is estimated, because of the physical size of the substation and the need to expand the footprint at approximately $3 million and so the project was originally proposed in the 2011 period and running from '12 through '17 to try to defer this $3 million upgrade for hopefully four plus years. We're aiming at four years, but in point of fact, if we're highly successful, that deferral can continue which is what we're hoping.

We've done a lot of work already in terms of the marketing around targeting efficiency and our tactics are specifically reducing the air conditioning load in the area and, again, to be clear, we say reducing the air conditioning load, we're not turning anyone's air conditioning off, we're simply cycling them and/or raising the temperatures that they'll operate to. So instead of your set point being 68, 69 degrees in your home, we'll raise it to 70, 71, 72. If you shut them off, you won't get people to participate because they just won't want to be shut off and be hot in their homes. So a key component with this sort of thing is the comfort of our customers to make sure that they're not -- because they simply will not participate and won't be able to use them. So we started the load relief in '14. We've got some numbers coming up here and I'll talk a little bit about the collaboration with the OER about some of the solar overlay, if you will, to what we're doing with targeted efficiency and demand response in this footprint.

So Slide 9 is kind of the timeline of when we started the project, and below you'll see the estimate into how much reduction in peak load we need over the course of the five years of the pilot. Summer of '14 through the summer of '18.

You'll note in the far right arrow, the key point here is to maintain participation. I talked about anyone can do a flash in the pan project and get hundreds of kilowatts of load reduction for a couple hours. That's really simple. The real hard part is getting the hundred kilowatt load reduction Tuesday, Wednesday and Thursday afternoon because the heat wave went through the week. And as importantly, our experience is that if heat waves go through the weekend, that following Monday and Tuesday become super peak days because everyone is back to work and everything else. So rarely are you going to call an event one day of the week. You'll likely call it more than one day, hopefully not the whole week, and depending on the extent of the heat wave, you may have to wrap it into the next week. So you have to worry about customer fatigue and all those other things about what we're doing here. But again, that's the proposed load reductions.

And under No. 10 is where we have

to understand -- we talked a little bit about one of the drivers, and obviously, we know in the pilot the summer months is the driver with the air conditioning load, later afternoon, 3:30 to 6:30 p.m. or so is the peak window. It looks like it's slowly moving a little bit later which doesn't surprise us. None of us like to go to bed on a hot humid night without the air conditioner running in our bedroom and we actually have plenty of circuits that actually peak at 8:30 or 9:00 o'clock at night because of that effect. Even though we did have a peak, a lower peak in the afternoon, the actual feeder peak can occur and in many residential circuits does occur at much later at night. And what kind of technologies can we use and what again the customer based in the area is primarily residential and the rest is really small commercial.

We've done pilots -- actually we've did a pilot in the '06 timeframe in this area at the Kilvert Street substation which feeds this area specifically, but we only enrolled at that time large commercial/industrial customers who had energy managers and could manage their loads better, and in those cases you only needed a handful of customers to get hundreds of kilowatts or a megawatt of load relief. You have residential customers, you might get one or maybe one-and-a-half kilowatts per. We need lots and lots of customers. So if you recall, it was only 5,200 customers. So that's the population we have to work with. It's not like the systemwide ISO programs that have the whole New England footprint to play with. We have a very small footprint and a relatively small number of customers to get our megawatt of load relief.

Getting to 11, this is where some of details are coming out here. Key point in the upper right corner is the benefit/cost ratios. You see that every year and the overall is over one for the programs. The tactics really are about reducing the air conditioning load, the central AC and also the window air conditioning load where we actually -- in both cases we are using the customers' broadband connection to talk to their thermostat and then through that internet connection we then call the thermostat, or what we call a smart plug which is used for the window air conditioners that plug into the smart plug and then that plugs into the wall. Cindy?

MS. WILSON-FRIAS: Is the benefit/cost ratio, is that just for this program or does that account for energy efficiency measures that you're also trying to get the customer to participate in?

MR. ROUGHAN: That includes both.

MS. WILSON-FRIAS: Okay.

MR. BIANCO: It doesn't include, though, any funds for solarized or anything?

MR. ROUGHAN: No. No. Those are separate. Separate funding. So to work that out, pulling those costs and benefits apart is going to be a fun challenge.

MR. BIANCO: Good. I'm glad it

will be fun. Can I ask also, the customer base, I see your projection here. I mean, you're expecting that split to stay about the same. It's my understanding there's been proposals for a mall and a casino in the Tiverton area. Would that possibly affect this project?

MR. ROUGHAN: Yeah. Those are both in northern Tiverton. They're not on the feeders we're talking about. And that's the challenge, too, when we talk about marketing. We talk Tiverton, but it's not all of Tiverton. Our feeders or substations don't just feed one town. So the marketing efforts are a little bit more challenging in terms of how you reach out to customers, because Little Compton, it's the whole town, but Tiverton is just the southern part of it.

So we've been installing wifi thermostats, the plug devices. We moved into this year if you look at the '15 to '17, things like heat pump water heaters, more efficient clothes dryers and continually recruiting and getting new customers and maintaining the existing base.

When we came -- the second -- I think the second or third annual filing there was a lot of focus on why is your marketing money higher than it was before? The reality is because it takes a lot to engage these customers. Most customers, if you've got one or two cellphones you're paying for, smart phones, your cellphone bill is probably higher than your electric bill on average. So the apathy is just a real issue that we have to deal with. Customers do what they do every day. They don't want to worry about their energy bill because for many people, yeah, they don't like it, yeah, they'll call and complain to us, but it's just one of those things that they don't seem to do a lot about without really helping them focus on it.

COMMISSIONER DeSIMONE: Their cable bill is a lot higher, too, probably.

MR. ROUGHAN: Exactly. But we've got a good -- so far okay participation.

The challenge really is coming up in these next few years. How many more people? We've reached out to the population a number of times, and what's been helpful for us is a lot of telemarketing, a lot of door-to-door knocking which some people like, some people don't, but it really needs to be done in order to get people to focus on this.

In the lower right corner you can see the performance so far and you'll see that so far we're doing fairly well. And our projected, we're expecting naturally for it to be higher than what we need, and the need does change slightly year on year based on actual loads. We see the prior summer and what the anticipated load growth in the area is. So there's not lot of variation but it does vary a little bit.

So Todd, for example, if there was something big proposed in the area that would be asking for two megawatts of load, well, we'd just pack up shop and go look for somewhere else because we really can't --

you would have to then build something for that at that point. And that's the other variability we've got to think about with non-wires is we can only predict what we can, and if something big happens, then we really have to worry about it. But the converse is true, too. We may well build an upgrade and then that casino closes and that load goes away. So that's the other the flip side of the coin we have to worry about.

MR. BIANCO: So what I was wondering, though, is I mean, how -- if this were possible to have -- not possible, I'm sorry, if a large customer came in and wanted to interconnect and sort of caused you to wash your hands of this project, you made a motion, it's not on the record, then, I mean, would you at that point, though, explore other options? Perhaps total net cost would be cheaper to get them to find a way to interconnect to some other feeder perhaps than to abandon this project? Like, I mean, does that type of analysis go on or do you just say no, that's it. You interconnect to the closest feeder and we walk away.

MR. ROUGHAN: We would look at that customer's needs and try to make it possible for them to connect to the system just like any other customer request. And if we could also work diligently with them to do super efficiency and super load management so that their impact at peak was much lower than something else, that may still be able to work and we could still work with that customer and still keep the pilot running. So it would make a difference. It was only -- because homes still are being built in the area. It's not as if there's no building still going on there. So there's still some load growth. But working with new construction folks and the efficiency world trying to get that while you can is a critical piece as well.

So getting to Slide 12, this is where we kind of talk about some of the solarized opportunities here. This is where we work closely with Danny and the team over there to look at how can solar reduce peak loads, and frankly, we were surprised what they found. One of the real interesting things was for the three summers that they looked at the peak loads in the area, cloud cover would not have been an issue during the peak hour which is one of our fears when we look at solar. You think of solar array and clouds come over and it all goes way. Well, for the three summers we had the data, and again, it's a very short time, cloud cover wasn't an issue. So that kind was a surprising output of the study that Paradigm did for us.

But they also showed very clearly how if you reoriented the solar panels how you can move the peak output of the solar panels much closer to our peaks on the panels here. And the table below shows the amount. And to be clear, we simply selected a value of effective solar. I use the term effective solar because even with westward facing panels, you won't get the full nameplate solar array at four o'clock but instead of only getting 25 percent of it, hopefully you get 35 or 40 percent of it. So that's where the nameplate -- so we selected kind of this 250 kilowatts and backed into the how many kilowatts of solar that would require. And I was just talking to Danny earlier. It sounds like we've got a -- what are the numbers again that you said we've got signed up already?

MR. MUSHER: The latest numbers I saw was like 120 kW in Little Compton, 160 in Tiverton, so it's coming along nicely with another month of the campaign.

MR. ROUGHAN: Great. So that's going to be really helpful to understand how that really does affect the peak in the area and combined with the other things which the company is doing as well. So a lot of lessons so far.

Engagement. I've talked about this a number of times. This can't be talked about enough in terms of getting the engagement of the population. I mean, it's easy to sit back and say oh, yeah, folks will do this. Of course they will. You pay them this. You pay them that. Of course they will. Reality is a very different animal. It just is. Folks have a lot of other stuff they do. I'm an energy geek. I'll admit it. I think this is cool. I do all this cool stuff in my house, but my wife won't. It is what it is. We have to -- how do we engage those populations? My mother is in the smart energy solutions footprint in Worcester. She doesn't give two doodily you know whats about what we're doing in Worcester. She wants to make sure she's cool in the summer and warm in the winter and she has her lights so she can read her books. That's what she cares about. So as long as we can meet those needs, we can manage that population, but that's the other piece we have to learn.

MR. ZSCHOKKE: Tim said he has to go to his mom's house and manage the load.

MR. MUSHER: Tim, I also want to be warm in the winter and cool in the summer.

MR. ROUGHAN: But saving money sometimes didn't really -- doesn't really resonate with some people, it just doesn't if it's not a lot of money, and that's something out there. Plus frankly, people are suspicious. Why do you want me to reduce load? It reminds me of our old energy efficiency days when we first started the programs. People were looking at us cross-eyed. What? You want us to reduce what you sell? It just didn't make sense to them. We still get that. When you start to activate control devices in customer homes, this issue about Big Brother isn't insignificant. People really have a serious concern about someone knowing more than they want them to know about their own business. And how do we get through that? It gets very interesting to have those conversations.

COMMISSIONER DeSIMONE: Yes, especially when we're learning that the federal government is storing information regarding all of our phone calls, et cetera, so it plays into all of that, right?

MR. ROUGHAN: Bingo. It absolutely does. And what we've learned, too, is not one shoe fits everyone. We have to have a lot of different activities and opportunities for customers to pick what they want out of there so you need a fairly extensive menu of options and that gets -- there's an additional layer of complexity and management that that has out there. So that's where we've got there on Slide 14 making it as simple as possible is always important. Once you get the customer to agree to the automation, it's great. One of the interesting things we found out in a test last summer was that customers hadn't installed their window air conditioning units yet because it hadn't been hot enough. Most of us kind of wait. Leave them in the garage or cellar until it gets really hot, because we know when we put them in, our bills are going to go up. So if you haven't put in your air conditioner, your smart plug is not doing a whole lot when you say hey, turn off your air conditioner. So that's the other thing. You have to make sure folks remember when you plug in your air conditioner, make sure it goes through that the smart plug. That constant reminder is also important.

COMMISSIONER DeSIMONE: The thing with the window unit is once you put the window unit in you can't open your window anymore either, so on a cool day you're stuck with the window being closed.

MR. ROUGHAN: Exactly. So that's the other -- so when you're doing plug load control you have to make sure the plug load -- how do you make sure they're there if you expect control? The good news is if they're not there, they're not contributing to the peak load either. Just like your earlier comment about that light bulb that someone is not using. Well, they're not using it so instead of 13 watts, it's zero watt that time. So there's that other thing.

We do have to test these things. You have to get people understanding the program and so that when there's a test they know what's going to happen, there's no surprises out there, and that's a critical piece. One of the interesting things we had to do in the pilot, still been doing it is we're physically going to people's homes because we have incentives for window air conditioners as well for new air conditioners. But we want to get rid of the old inefficient ones. The only way you can guarantee you do that is if you send a truck over there and saying knock, knock, knock, I'm here for your air conditioner. If you expect them to go and drop it off, most people are going to go, oh, it still works. I might need it, or my cousin will want it. Whereas if they're really going to get the incentive, you've got to take that out. Just like our second refrigerator deal.

MS. BESSER: I would think customers would like that because they charge you in my town if you throw out any appliance, so I'd be thrilled if you took my old appliance.

MR. ROUGHAN: That's one of the things we learned from the program. That's the presentation. Again, I'd be happy to answer questions. I will admit that Lindsay Foley could not make it today. She's our expert on the ground, project manager. She knows every little detail about this program that I'm a little bit distant from, but I think I can probably answer most questions.

MS. WILSON-FRIAS: Have you started to roll out the water heater program for the water heater controls or the things that you mentioned on Slide 11?

MR. ROUGHAN: So mostly with that, that's where we're actually looking to replace the water heater with a heat pump water heater, not so much control it, because that's separate -- you want to control water heaters and swimming pool pumps. There's actual physical equipment that has to be installed by an electrician so you can get a switch in there that has a connection to the customer's broadband. So that's kind of one of those things that we're hanging back with, that if we need to go to that point, we can go to that point.

MS. WILSON-FRIAS: How did you used to control the water heaters? My grandmother had one of those.

MR. ROUGHAN: Many moons ago. We bought a small spectrum over FM and AM radio stations in the area and the controller was actually controlled by a radio signal on those old water heater controls, but those were installed to manage the load when we were vertically integrated. So the key part, typically to manage those early morning winter loads because way back then we were winter peaking. A lot of us grew up without air conditioning in our bedrooms in our homes. And now that's just not the case. But back then the winter peaking system, the water heater control really helped to manage that winter peak. But the problem with that was that when we went to restructuring 17 years ago, it was 17 years ago, not just this winter, there was no need. We didn't own the generation anymore so all those programs were essentially ended at that time.

MS. WILSON-FRIAS: I guess the reason I had asked was because if it was accepted back when I was my kids' age, then I didn't know if it would have even more acceptance. You talked about the Big Brother piece of it, where it's already been done in the past under a different technology.

MR. ZSCHOKKE: Right. So when restructuring came, the idea behind restructuring was that the market would deliver better than the utilities. So we eliminated all our demand response programs, commercial/industrial and residential, so the radio frequency we purchased we kept for a while, but it was an expense nobody wanted to pay for anymore so it got stopped. But there are probably water heaters out there with radio controls on them to this day, right?

MR. ROUGHAN: The other thing, though, we also used those large 80 and 100 and 120 gallon tanks so we had plenty of storage and those would only turn your water heaters off for two to three hours. So rarely did you run out of hot water because the things were so large. But again, it's been a long time. We went through the analysis of the water heater control program back in the early 2000s in the company and we tried to justify keeping it because I was working at the time on some of these other pilot programs, but there's no way to pay for it. The forward capacity market wasn't there. There were no programs that could pay for these sorts of expenses in place at the time and no real value we could talk to to continue to ask different regulators to continue to fund them.

MS. BESSER: I wanted to followup on Cindy's questions which I heard it differently. I thought you were saying that given experience with some direct load control, with Big Brother type issues raised at that time, if customers did this once, why is there an issue doing it again is sort of what I heard you asking.

MS. WILSON-FRIAS: It is kind of what I was asking and I'm wondering if maybe it's a different technology that you would use now, a radio frequency. You're not actually seeing where the broadband internet connection, public TV shows right now.

MR. ROUGHAN: The radio thing was the only way to communicate with those.

MS. BESSER: That may have been more innocuous to customers.

MR. ROUGHAN: Probably. But I mean, the challenge of the water heater program, it was so long ago it's hard to reconstruct how customers felt about it. Customers used to -- it was part and parcel of our rental water heater program. If you were part of the rental water heater, you also got control. So instead of having to buy a brand new tank and then pay to install it, you could simply sign up to rent a water heater in the '60s and '70s and we'd come in and do everything for you and it was a really nice way to, frankly, promote electric use at the time because that was what electric utilities did, but also manage the control because of the winter peaking issues.

MR. MUSHER: Tim, so I think it was either in the three-year plan or the 2015 SRP, but probably the three-year plan that we had one of those -- the new theme of non-wire alternatives as partial solutions. And so that you might have a -- that wouldn't defer the entire need but part of it, and you mentioned how when you're looking at a lot of the investments that you need to make, a vast majority of them have partial access, partial reliability and growth. And so when I look at the criteria that you have here, the four criteria, how are they -- is there a difference in how you apply those -- how do you apply those criteria in the case of looking at non-wires alternatives as a partial solution? Is it a different process or can you use the same four criteria?

MR. ROUGHAN: I think we can use

the same criteria. And what Danny is talking about is you've got a solution that you think is going to cost you $5 million but if you're doing some non-wires, your solution is only going to cost -- because what you have left is only a million, then you can defer 4 of the $5 million. And that's a new concept we're just starting to work on with our planning folks at this point. So we're still trying to work out those details there because we were initially saying can you do non-wires for the whole thing or not and now we're morphing more to that's still a thing, can we do the whole project or not or how do you parse it out in particular areas so we can do just partial non-wires and we're still working on that. We don't have that flushed out.

MR. MUSHER: Okay.

MS. ANTHONY: So Tim, one thing that a few of us have been talking about in this small group, Jeremy, Charity, Marion and Danny is we've defined system reliability, all of us, including the standards that have been approved by the Commission, as a strategy for avoiding a specific transmission or distribution deferral or a partial deferral, but is there a way we can take that same I'll call it mentality or approach to using non-wires alternatives to optimize the system or improve system performance, make it more efficient rather than necessarily avoiding a specific upgrade. And I would just -- I guess I'm looking for your thoughts on whether that is something at some point in the future we could try as a pilot as well.

MR. ROUGHAN: Well, the good news is between all the pilots, right, the SRP, the smart energy solutions up in Massachusetts, the volt/VAR pilot we're working on, all these things are kind of coming together in terms of showing clearly the need for greater visibility into the system, the need for more sensing, the need for more data on a realtime basis to manage that. In order to optimize the spend, you really need to know what you're seeing.

It wasn't that long ago that all we knew on a feeder was the peak load from the last time we reset the meter. We didn't even know when the peak load occurred. We just knew what it went to. Old thermal demand meters is what they are. They just go up as the load goes in. They stick until you reset them.

In the last 10 or 15 years as we upgraded all our substations, we now have the granular, really down to seconds, if you will, of load at many of our substations, all the newer ones, but we still only have it at that breaker at the big substation. And the feeder might be two miles long, it might be ten miles long. What we don't know on a realtime basis is what's going on on that circuit and that's where the real need to invest in the systems to get more data so we can make those decisions is critical.

We also have to recognize even the pilot in Little Compton/Tiverton is still just a pilot. We don't have -- we can't label it a success. We can label it a success that we started a project that's going to be very important to all of us, but until we can really see that one megawatt load relief, you know, day after day when we call it, it really can't be coined a success at this point. But the need for that additional information on the system is going to be what drives the optimization of the delivery system. And that includes getting down to potentially interval meters at that residential level. There's a lot of value in that. Today the costs may or -- may be a little higher than folks may be willing to spend, but over time we expect those costs will drop, too, and as we move forward we can potentially install additional equipment and actually that's how we give customers that time varying signal and also that's how they know if they're on a demand rate when they're approaching their peak demands and prompting them to do something about it or prompting their building management system to automatically do something when they see demands rising above a certain pre-set level.

THE CHAIRPERSON: Are there any more questions or comments?

MS. GOLD: I guess I have one more. I was just looking at something where Consolidated Edison had won approvals to replace an estimated $1 billion in substation upgrades with about $150 million in targeted demand response and energy efficiency programs and another 50 million in grid scale battery system providing an early template of how distributed resources can work in lieu of utility assets. So I guess this gets to the question that we talked about a little bit earlier when you have a Tiverton casino coming in, how do we help encourage the utility to look at alternative resources instead of just putting in a billion dollars.

MR. ROUGHAN: I think you have to look at the scale and the other issues surrounding it. Con Ed is a huge utility, but the scale of what they serve in terms of load density, in terms of customer density is phenomenally much more massive than anything we have anywhere in our system in National Grid. And they also have physical limitations in their footprint in the city. In Brooklyn, you just can't get the length, even if it was available. A, it's not available. B, if it is available, it's wildly expensive. Everything in Con Ed costs a lot more than it costs up here so they can do lot more things like this that make lot of sense. But when we upgrade a substation if you compare the Tiverton cost new feeder of $3 million versus what it would cost Con Ed to build the same thing, it would probably cost them ten times as much because it has to be all underground. It has to physically fit in locations where -- and it didn't have area. Tiverton, we just push the substation fence out a little bit, get the proper permits, build the line and it's pretty straight forward without a lot to worry about, versus downtown urban Brooklyn and New York City.

MR. ZSCHOKKE: Tim is right. You have to keep in mind that I don't think there's any utility in the world that can be compared to Con Ed's system, and as my favorite engineer described to me once, the megawatt we're looking at for Tiverton/Little Compton is like a fly on an elephant's butt when it comes to -- on an elephant when you talk about Con Ed. They didn't like the hundred kV rule that FERC put in place because they use 115 as local distribution. So I mean, they have -- the density of load is phenomenal. And how their network is designed, if they save a megawatt of load on any feeder, it can automatically be used to serve much larger areas than we would ever imagine because everything is all connected, a very broad swath of a very tiny footprint.

MS. BESSER: Can I ask a follow-up? The point I took away from Marion's question is actually National Grid is also a very large utility and it may be that in Tiverton you're not making this scale of investment, but as you look at major investments, I think at least what strikes me, I'll say, from my perspective, but as you look at major investments I think some of what we want you to be doing is looking at non-wires alternatives to even major investments where they can save customers money.

So Tiverton is a pilot, it's a different kind of thing, but there are, I imagine, places on the National Grid system where you make major investments, not the same density, not the same kind of investments as Con Ed, but I imagine your capital plan includes large investments.

MR. ZSCHOKKE: Conceptually we're all in agreement. The difference is the megawatt we save in Tiverton/Little Compton hopefully can't be used in Providence. Whereas for Con Ed, and I listened to one of their engineers, their system is so closely networked and works so coordinated, the megawatts they save here will be used in a whole lot of other places and so they don't mind having these programs for that reason, but it could be spread across a lot of their area of their service territory where ours tends to be very focussed on the area where we're making the investment.

MS. BESSER: I hear you on that. But I think it's about scales of investments. Where you might need a major investment in a major substation, it might look different from Con Ed, but I think you're still -- I think there's still -- the focus is how do you have distribution planning proceed in such a way that you look at alternatives to just upgrading the substation or whatever you're doing.

MR. ZSCHOKKE: It's the same concept.

MR. ROUGHAN: Well, those four criteria we talked about are used every day by our distribution and transmission planning folks. And every day they look to see what they can do for the project that they've got out there. And some states are more amenable to that than others. Rhode Island has been very supportive of it. New

York State, Massachusetts hasn't been, surprisingly. So they do for every project figure out what they might be able to do from a non-wires perspective but, again, the premise still is until we see that one megawatt every hour of every day that we need it for every summer we need it, it's difficult to say I can hang my hat on this thing. We're confident we will be able to, but we really need to figure out all the ins and outs of that customer participation and engagement in a highly managed way before we can say yes, this -- we can and should do this everywhere because we still have the obligation to serve.

MR. BIANCO: May I? Just one? I guess the final thing that still -- the question that I always want to know is when you think of least cost procurement you can have -- you have benefits and costs. The benefits you might achieve through a program and the costs that you calculate you would want to be the same through some other method of achieving those same benefits and costs. And while we have the history of benefits and costs for SRP and energy efficiency, I wonder if some of this can be done, some portion of benefits with some different costs can be done through metering and rate setting, and I have no idea how much -- the type of metering costs or what it requires, but my -- economically you must be able to get some reductions through proper rate setting. I don't know how much it is, but that would be the benefit. And I wonder, I don't know what the costs are of these types of systems and I don't know if there's reports out there or anything like that, but if we could ever find out, if anybody has that and wants to give us an idea of what a proper system would require in order to be able to set the type of rates that would get us comparable benefits to, say, a Tiverton program or something like that, that would be -- that would be heck of a report I guess or a filing.

MR. ROUGHAN: If you recall in the ISR discussions, I did mention advanced metering infrastructure depending on what you're getting and the granularity you really need and the latency of the data can be $100 a point, it can be $400 a point. It depends what you're looking to get out of the system for the end use meter and the back office system to manage all this data that you didn't have yesterday. So that's where you need to kind of look at what are you trying to do with it? Do you really need five-minute data for every customer or can you get by with the data for a three-hour window?

MR. BIANCO: Let me say, then, one principle of least cost procurement is to go out and get the -- what you need to procure for the least cost. If you have this procurement, let's say energy efficiency and you wanted to achieve that, would you start with that amount of energy efficiency or that amount of demand that you would achieve by some other means which is cheaper than going out and building more infrastructure and procuring more energy. You would say this passes. Let me see now what it would cost to get those same benefits through rates, and if it were cheaper, that's actually least cost procurement, right? If it's not, you've got to go with the programs. And I don't know what that cost is. And I don't know if at some point that could ever be studied or part of planning. But that seems like that would fall under least cost procurement principles.

MR. ROUGHAN: Costs or -- maybe I'm missing something, Todd.

MR. BIANCO: For metering and for running a back office that handles that type of --

MR. NEWBERGER: System integrity? I think you're suggesting somewhat of an expansion of the definition of least cost procurement at the same time. We've defined least cost procurement as resource acquisition, megawatt hours or kilowatts, and some of the things that you talk about about rates or time differentiated rates, some of them may lead to consumption reductions but some of them may just lead to shifting. So if you expand the discussion to that, we'd also have to expand the discussion of whether that's -- whether you're requiring the megawatt hours of energy reduction that you're looking for. So it's a -- I think you're teeing up a broader discussion that may be fit for another day.

MR. BIANCO: I'll allow that. Okay. I mean, probably. I often do.

MR. ZSCHOKKE: If you're talking, Todd, about the cost to implement an AMI system with back office communications, there was at least one document prepared in the Mass. grid mod that we can copy actually comparing installation costs of different systems across the country. But as Tim pointed out, the delta of those costs may be generational as they change technology, but also how you design your coms and your information network.

There was a person on the panel with me yesterday who said he was frustrated because trying to work with his customers with the AMI data, nobody who has an AMI out there now is providing realtime information. So you're getting the data the day after, even though they have all these meters, and that's based upon how they've designed their coms network, how they've designed their information retrieval network and how they've designed the access to the data realtime.

We can obviously give you some information on our smart energy solutions pilot, what it's cost to do the 15,000 meters there. And we've designed it so that we retrieve the data every eight hours, but customers can log in and ask for the data and then they can get immediate access to their information, so they do have a realtime polling of the data available to customers who want to do so. So it's different level of costs. We can provide that information, obviously, because we're in the middle of doing it, but that's -- that's the information I know that could give you some handle on what the cost of the system would be.

MR. LeBEL: If I can jump in, I think that the answer to Todd's question might be hopefully part of your grid modernization filings in Massachusetts with both the costs that you mentioned and maybe even some analysis benefits hopefully at some point.

MR. ZSCHOKKE: It will give him a range, but I think until you get a final statement of work signed with a contract, a vendor or vendors, you don't know what the final costs will be, what the finalized bids will be. Our smart energy solutions pilot feeds into what we're doing with the grid mod pilot. Tim is the master of grid mod right now.

MR. ROUGHAN: Yes, I am. Next question please. But Peter is right, I'm heavily involved with the AMI part of our proposed grid mod filing.

MR. BIANCO: I'm sure your mother is both comfortable and proud.

MR. ROUGHAN: It depends. Some days it's Timothy. Other days it's Tim. I know what the difference is.

THE CHAIRPERSON: And on that fascinating note, perhaps, we're done.

(ADJOURNED AT 2:23 P.M.)

C E R T I F I C A T E

I hereby certify that the foregoing is a true and accurate transcript of the hearing taken before the Rhode Island Public Utilities Commission, on May 14, 2015, at 9:30 a.m.

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JO ANNE M. SUTCLIFFE, RPR/CSR
Notary Public, State of Rhode Island