BEFORE THE
ILLINOIS COMMERCE COMMISSION

IN THE MATTER OF:

111(d) POLICY SESSION 2

Chicago, Illinois
September 23, 2014

Met pursuant to notice at 12:45 p.m.

BEFORE:

MR. DOUGLAS P. SCOTT, Chairman
MR. JOHN T. COLGAN, Commissioner
MR. MIGUEL del VALLE, Commissioner

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CHAIRMAN SCOTT: Everything ready down in Springfield?

MR. JIM ROSS: We are ready, Mr. Chairman.

CHAIRMAN SCOTT: Very good, thank you.

Well, good afternoon and welcome everyone to the second of our three-plan Policy Session on the Clean Power Plan or the Section 111(d) EPA Rules, the proposed rules.

With me today are Commissioner John Colgan and Commissioner Miguel del Valle. Commissioner Colgan has to head back to Springfield tonight, so at about 4:45 he is going to leave our meeting. So if you're speaking at the time, it's nothing you said that made him get up and leave. I just want to make sure everybody knows that.

But we're very glad that all of you are here as we want to do a couple of things. We want to make sure that as we go through today's agenda, we're really focusing on Building Blocks 3 and 4 of the proposed Clean Power Plan rule. As you might recall, our first session last month dealt with both an overview of the Section 111(d) Proposed Rule
as well as Building Blocks 1 and 2 that we went into a little bit more in depth. And then, our final section for those of you who have been following the dates, there is a change in the date to announce; it will be in the afternoon of November 6th. Originally it was scheduled for October 30th and that has been moved to October 6th. We are also planning -- I don't know they're here or not, but Representatives Elaine Nekritz and Robyn Gabel were going to join us today as well as the legislative director for Senator Biss, Alison Leipsiger. So we're very, very, pleased that they're here. And, again, if we go into the third session that becomes -- I believe will become very important as well -- their input as well.

So we have a very packed agenda today.

If you've seen the agenda, you know we've got 15 different speakers who are going to be here today. This is going to be a little bit different, though, than what we did the last time in that we're asking the rest of you folks to make very, very brief opening comments, no more than five minutes because the idea is to have each panel have a conversation
about the topic that they're presenting on. So we think that just having at least a five-minute overview from each of them is good because it will help set the table for the discussion. But we are going to have to hold the speakers to that five minutes as you can see, because we've got a large number of folks to talk to us today. The goal, of course, is to have a better understanding leading up to the November 6th session, where we're actually going to look at compliance pathways and how do we actually take everything that's in the proposed rule. And assuming that it were to stay there or something very similar to that, given all the information that we have gleaned from the first two meetings, how then do we develop some compliance pathways that will allow Illinois to comply with the rule and what's the best way for doing that.

Commissioner Colgan, anything from you to start?

COMMISSIONER COLGAN: No.

CHAIRMAN SCOTT: Okay. Well, I'll start with the first panel then. Jim Ross, that you can see on
the screen, is once again joining us from the Illinois EPA, and he's down in Springfield. Jim is the manager of the Air Pollution Control Division.

And then, if I could have the other panelists come up to the table, either the one facing us or the one to the side. Either one will work.

Then the other three panelists are Kathleen Barrón, who's the Senior Vice President for Federal Regulatory Affairs and Wholesale Market Policy at Exelon; Paul Sotkiewicz, the Chief Economist, the Market Services Division of PJM and Todd Ramey, who's the Vice President of System Operations and Market Services from MISO.

So thank you all very much for being with us today. We're going to start with Mr. Ross. And, Jim, you want to give us your -- go ahead here with your five minute overview.

PRESENTATION

BY

MR. JIM ROSS

Thank you Chairman Scott and Commissioners. Hello to all of those in Chicago and
those here in Springfield. For those listening in, I believe my presentation slides will be made available shortly after the session.

Okay. My mission here today is to set up the stage for further discussion on 111(d), and in particular in this first part, on how nuclear energy generation is addressed in the proposal. I'll start by saying that we continue to do a large amount of outreach at the Illinois EPA on 111(d) and this includes myself, our clean air policy advisor Kevin Greene, and, of course our director, Lisa Bonnett, who has been very engaged.

In our numerous discussions with stakeholders, we often get asked about the nuclear component of 111(d) and the simple answer is, It's not simple; in fact, it's complicated. However, it is very, very important that we do understand since nuclear energy plays a significant role in how Illinois gets it's power. Illinois generates more nuclear energy than any other state.

And I do recognize I have some time constraints here, so I have more slides than I'll go
over. Some of them are provided for you to go over at your leisure; but I will hustle.

So the presentation that I have and how it's formatted, some background information; some information on the adjustment of Illinois' goal for a nuclear generation; U.S. EPA'S assessment of nuclear generation in the proposal and their thoughts on the preservation of nuclear generation; the determination of Illinois' at-risk amount and the impact of the loss of nuclear generation on the ability of Illinois to meet its goals in a short example.

So some brief background, but necessary background is, Illinois has 17 coal-fired power plants with 45 electric generating units. We have around 30 natural gas-fired power plants that are subject to the rule, now, this could vary because it's dependent on the amount of power that they provide to the grid. We do have six natural gas combined-cycle plants with their megawatt capacity around 3,400. We have six nuclear plants around 1,200 megawatts capacity and wind capacity in 2012, we had 2,700 megawatts and that did grow to around
Okay. You can see from the chart here -- and this is familiar for those who attended the last policy session, Illinois gets roughly 50 percent of their power from nuclear. In a close second is coal-fired around 41 percent, that makes up 90 percent of our generation. The remaining 10 percent is nearly split evenly between natural gas-fired and renewable energy, which is primarily wind.

This is a familiar table for those in the last policy session and we'll just focus in on a few aspects of this. But in essence, it provides a broad overview of what U.S. EPA did in the calculation of Illinois' goal. In row one, there, you see the unadjusted baseline or unadjusted emission rate from all the effected units, and that's the 2,189 pounds of CO2 per megawatt hour.

In row 2 there is our adjusted baseline, which is 1,895 pounds CO2 per megawatt hour. And how is it adjusted? Well, you see the asterisk, you follow that white arrow down; the black
rectangular box at the bottom shows that they
adjusted the baseline for 100 percent of the existing
renewable energy generation in the state in 2012, and
5.8 percent of Illinois' historic, or 2012 nuclear
generation.

This is kind of a visual of the last
slide to give you a different perspective. There's
two equations, there's a top equation and a bottom
equation. The top equation is the unadjusted
baseline, so that has not been altered for RE and the
at-risk nuclear; it's the 2,189 from the previous
table. The bottom equation is our adjusted baseline,
and you'll notice the two purple balloons at the
bottom. That's what's been added for the adjustment.
It's the existing RE generation of greater than 800
million megawatts per hour. And then, the far right
below is the at-risk nuclear, 5.8 percent of our
generation.

And, referring back up to the top, you
see the black balloon in the upper right-hand corner,
it shows that there was a 13 percent adjustment
downward. Eight point three percent of that 13
percent was the existing RE; so the entirety of Illinois' renewable energy in 2012 but only a portion of the nuclear, and that was the at-risk nuclear portion, and that's the 4.7 percent of that 13 percent.

And one final table here, it is kind of a busy one, I recognize that. It shows a lot but we're going to focus in on the last column on the right with the yellow highlight, and that just takes us step by step, down through the adjustment process, down to the final goal. So it started with our 2,189 unadjusted baseline, which is the initial rate from all the fossil fuel-fired units in Illinois. They took it down 8.3 percent for the renewable energy, 4.7 percent for the nuclear energy, so it's on a cumulative basis. So we walk down all the way; we go through building blocks which this applies: 1, 2, 3, 4, until we hit the final total adjustment of our emission rate was 42 percent. But it's really only 33 percent because we can, in essence, get back all the existing RE and the at-risk nuclear to the extent that we preserve them. So that's a very important
concept to remember as we go through here.

I'll kind of skip over this slide; it's just by the numbers. It provides information that we've already given or provided previously.

Okay. So now that we know how they adjusted Illinois's goals and by how much, we switch to the reason why they adjusted the goal for nuclear generation. And we start with the statement at the top here, it says, "U.S. EPA Determined Building New and Preserving Existing Nuclear is a Viable Policy for Reducing CO2 Emissions." So we need to verify this statement, and we can pull out some excerpts from the rule and from the technical support document on the proposal.

The first bullet point here is, U.S. EPA position is that nuclear generation has zero CO2 emissions, it's carbon-free, and they say this in several places throughout. And then the second bullet point is a pretty long statement that I've pulled from the rule that in sum, the U.S. EPA is saying that nuclear energy provides power and has zero CO2 emissions in doing so, unlike fossil
fuel-fired units. Therefore, building new nuclear and ensuring existing or continued operation of existing nuclear, is a strategy states should consider, to ensure meeting their goals. Since there are no known concrete plans to build new nuclear units in Illinois, we need to focus in on preserving or keeping the nuclear that we have.

And so how does U.S. EPA address this? What statements do they make in the proposal? I've pulled out a couple of quotes here. The first quote is, "Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that would otherwise be retired." So avoid shutting down existing nukes.

The second quote here is, "...preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO2 reductions from affected EGUS at a reasonable cost." So cost-effective CO2 reduction strategy is viable for states to consider going forward.

And, finally, we need to understand U.S. EPA's thoughts on what the nuclear industry is
experiencing and why it was important to put incentives in the proposal to preserve this generation. And we start here with the first two bullet points, and they have a common theme that there's a revenue shortfall being experienced by the nuclear owners and operators. The first one is nuclear units are experiencing a revenue shortfall in covering their operating costs. And this revenue shortfall is creating an incentive to retire at-risk nuclear units.Offsetting this revenue shortfall at at-risk nuclear units is a reasonable mechanism to preserve at-risk units. Therefore, retaining operation of at-risk nuclear capacity should be factored into state goals.

So from these U.S. EPA concepts, pulled from the rule of the technical support documents, we can readily conclude, in the bottom black rectangle there, that U.S. EPA adjusted Illinois' goal downward so that Illinois would strongly consider providing a financial incentive to offset this revenue shortfall and avoid the shutdown of our at-risk nuclear units.
A few more slides, wrapping up some loose ends here. So how do they determine the at-risk amount? They look to the Energy Information Administration's most recent Annual Energy Outlook, which projected that 5.7 gigawatts and the nuclear capacity would be retired nationwide due to economic challenges.

So, again, we'd see this concept of a revenue shortfall and the economic woes of the nuclear industry. The second bullet point is the 5.7 gigawatts is 5.8 percent of the nationwide capacity. So 5.8 percent was considered a "reasonable proxy for the amount of nuclear capacity at-risk of retirement" in each state. And, finally, they used -- the U.S. EPA used 5.8 percent of the at-risk amount for all states.

Of importance here is what U.S. EPA did not do. They did not determine state by state the amount of nuclear generation at-risk, they simply used a proxy amount for all states. So it's important to note that Illinois may have more nuclear generation at-risk than U.S. EPA's proxy amount. And
I'll skip this -- this just goes over the numbers for determining the at-risk nuclear amount in Illinois.

Okay. These last three slides are to give you the sense of how what U.S. EPA did affects our goals and makes Illinois consider trying to avoid the loss of nuclear generation.

First bullet point simply is, any retirement or loss of nuclear generation makes it more difficult for Illinois to meet its goals. This is because a lower amount in the denominator can be used in our compliance calculations to adjust the annual compliance emission rate downward.

And I'll show this again visually with a couple of equations. This top equation this time is a goal; we have seen this before, the bottom equation is new. It's the annual compliance calculation that Illinois would need to submit to U.S. EPA and other states as well, to show that they're in compliance with their goals.

So if you look here at the top, we have in the denominator the 5,305,342 megawatt hours of nuclear generation. You can see -- you follow
that over to the black square, 4.7 percent downward adjustment. We hope that we'll be able to put that same amount into the denominator for our compliance calculations but that's only true to the extent that we preserve nuclear generation. If we lose some nuclear generation, then this amount would be smaller and we need to make up that amount of reduction somewhere else.

And I have a short example that will hopefully help explain this -- provide some clarity. At the top of this there's some givens here: Nuclear generation goes in the denominator. The bigger the number, the denominator, the lower the fraction, the lower the number the equation spits out. The second point here is the 90 -- greater than 91 million megawatt hours of generation that was used in the determination of the goals; it was more than any other state. And then you see the next number before, that's the number that actually went into our goal determination. So in our example at the bottom half of this slide, we just picked a year at random in between 2020 and beyond and this is 2025; if our
generation were to strengthen 71 million megawatt
hours, then we take 5.8 percent times that, we come
out with just over 4 million megawatt hours and this
would go in the denominator of our compliance
calculations. Clearly the 4 million megawatt hours
is less than the 5 million, so we would need to
somehow make up that difference from some other
policy that reduce CO2 emissions.

So I'll stop there and I hope this has
helped to clarify how U.S. EPA handles nuclear
generation in 111(d).

CHAIRMAN SCOTT: Thank you, Jim. Very good.
And we appreciate how the -- you correctly realized
that I'd misspoken in my beginning, and for this
panel and the next one, folks are going to do a
little bit longer presentations. It's only in the
last panel where we're limiting folks to five minutes
each. So in this panel and the next one folks are
going to take a little bit more time with that.

And also, I want to thank both Jim and
Director Bonnett at IEPA and Director Star at IPA and
Director Pollet at DCEO for helping to put these
things together and for participating directly in them. We are all working on these -- on this issue together and with IEPA's lead, and we appreciate everything that other agencies are doing with us.

Are there questions for Mr. Ross before we move on? And probably have some time left at the end.

COMMISSIONER COLGAN: Not yet.

COMMISSIONER del VALLE: No.

CHAIRMAN SCOTT: Anybody else?

(No response.)

Okay. Ms. Barrón, you're up.

PRESENTATION

BY

MS. KATHLEEN BARRÓN

Thank you, Chairman Scott, and thank you to the commissioners for the opportunity to participate today. I think Jim well laid out the contours of the EPA proposal on Building Block 3. I'm going to just highlight a few things about that very briefly, and then I'd like to talk about the economic pressures facing the state's nuclear fleet
and then at the end tie together with respect to how all that relates to how the state complies with the ultimate 111(d) Rule.

I think it's beyond dispute that maintaining an existing nuclear fleet is essential to meeting any of the department goals that the state has set or the EPA will set for the state. And I think, as a baseline matter, it's important to note that EPA has said we need look both at carbon per generation created and also carbon voided by different mechanisms.

So therefore, they've tried to include both emitting sources and non-emitting sources in this rule. They have, as Jim said, acknowledged that there would be a significant increase in carbon emissions if we fail to maintain the existing fleet, and Commissioner, excuse me, Administrator McCarthy has seconded that publicly, saying that if we don't preserve the existing nuclear capacity, that's a lot of carbon reduction that we need to make up from other sources for a long period of time.

As Jim explained, EPA also concluded
the preserving existing nuclear is -- it can be achieved at a reasonable cost versus other carbon-abatement options. Specifically, they use the $6.00 per megawatt hour number and they said -- and they view that as a reasonable payment in comparison again to other strategies for abating carbon.

Of course in a mass-based system, retirement of a zero carbon resource and its replacement with a carbon emitting source of energy would jeopardize the state's ability comply. So there's no need to explicitly include nuclear if you're going to have a mass-based system. But since EPA has proposed this rate-based system they had to come up with the formula and the calculation that Jim explained, and then they use this proxy, which was a government estimate of the at-risk fleet. As he explained, they sort of peanut butter that across all the states and then they ask for a whole bunch of comments on the aspects of that proposal.

But I think it's important to note even that government estimate is based on, really, the Midwest fleet. That 6 percent they put in the
Midwest, so it's really more like 26 percent according to EIA that is at-risk and very little elsewhere. And in truth, far more than 26 percent is at-risk here in Illinois.

I think it's fair to say that EPA views that 6 percent proxy really as a place holder to begin the dialogue about how to reflect nuclear in this rate-based formula. The proposal really begins with 2012 as a baseline emissions year and it's looking for progress from there. So I think it's fair to say that they don't expect there to be backsliding, which is what would happen if there was a premature retirement of a carbon-free resource.

When the Administrator testified on the Hill a few months ago, she said that she's really encouraging states to pay attention to this because replacement of a base low-capacity unit that is zero-carbon would be a significant challenge for states who are right now relying on those nuclear facilities.

So I think EPA's going to be looking to states as they develop their compliance strategies.
to make sure that they don't take steps that will undermine their existing carbon-abatement strategies.

Turning to the nuclear fleet here in Illinois, I'd like to say a few words about the current pressures that our plants are facing. As you all know the recent PJM auction, many of our units did not get -- in fact, four of our units did not clear in that auction, which means that their costs to continue operating are higher than where the capacity market cleared. And then we have a fifth unit in the state, our Clinton unit, which is in the Midwest ISO, which does not have a forward capacity payment. So as a result, you have those five units up, that's 43 percent of the nuclear capacity in Illinois, which does not have the capacity commitment for the 1718 planning year. There are number a of factors causing this, which include low natural gas prices and wind subsidies. But chief among those reasons is the absence of a market mechanism to value the carbon-free nature of nuclear power.

We don't expect the factors driving the economics to change in the near term, absent the
EPA's rule making. As you all know, we were originally on a schedule to make some decisions about whether to retire those challenged units by the end of this year, but at the request of policy makers, have agreed to defer that decision until May of 2012 [SIC] to accommodate the legislative calendar. But we cannot postpone indefinitely, obviously.

As you probably know, if the aim is to retire, they cannot be mothballed and brought back online at a future date. These five units together represent almost 30 million metric tons of avoided carbon emissions, given that they will need to be replaced -- to make sure the capacity needs are met by -- for customers in the state.

I'm sure Dr. Sotkiewicz can elaborate more on this, but nuclear plants provide unrivaled performance during all weather conditions. We operate our fleet nationally on an average capacity factor of 94 percent -- 93 percent, rather, the rate in Illinois is actually 94 percent last year, which means they're available 93 percent of the time to meet customers' needs even counting the time that it
takes to take them off-line to refuel them or conduct
scheduled or unscheduled maintenance.

Many types of plants, as you know,
struggle to perform during extreme heat or cold, when
the power is needed; but ours don't. For example,
during the peak of January's polar vortex the nuclear
fleet represented only 3 percent of the forced
outages at PJM.

I'm sure Paul will second this, as his
boss is quoted as being in favor of maintaining the
fleet for purposes of keeping the lights on. He has
said, and I quote, that "it's critical that the
nuclear fleet in our region remains economically
viable particularly as we head into this multi-year
transition and the rest of our resource profile."

He's also been quoted as saying that
the retirement of the nuclear fleet in PJM is quote,
"unthinkable."

Finally, turning to our state's
compliance with the EPA rule, I have just a couple of
slides that I think illustrate two important points
that we should keep in mind. Before I turn to them,
I just want to say I think it's odd there's two obvious compliance options, and if the state opted for a mass-based system, the loss of nuclear capacity would be significant, as I mentioned earlier, in that fossil emissions would increase, which would make the compliance with the cap more difficult and expensive.

In a rate-based system, of course, the impact of a loss of nuclear capacity depends on the extent to which it's reflected in the rate. And I would have to agree with many who've said that the 6 percent that the EPA has chosen, isn't much of an incentive to retain nuclear capacity. So I think that puts us in a position where if nothing changes in the EPA proposal -- as I said earlier, I do think EPA sees it as a place holder and is continuing to think about ways to address it and improve it, but if nothing changes, if there is a loss of nuclear capacity between now and the compliance period that could prejudice the states's decision to choose a mass-based system, even though that would be the more cost-effective path.

So if I turn to -- if I can turn
to -- and that's the first slide --

space bar -- thank you.

What we're trying to do here is just
demonstrate the significance of a continued operation
of the state's nuclear fleet in reducing carbon. All
together, the six stations that Jim mentioned
represent 65 million metric tons of carbon per year.
And we compare that on this slide to the amount of
abatement that we're currently getting from our RPS
Program in the dark green, and then the dotted line
is where our goal is. And likewise for our
efficiency programs, so I make this comparison, not
to suggest that we don't need all of these tools but
just to highlight the magnitude of the contribution
that the nuclear fleet is making to abate carbon in
the state.

Secondly, as I noted earlier, EPA
concludes that it will be reasonable to cover the
assumed shortfall of $6.00 in megawatt hours to
retain nuclear capacity, given the abatement costs of
other alternatives. And so what we've done here is
translated that $6.00 into a carbon price and overlay
that on to market price, in the regions that are represented by the green bars on the right and contrast it against the cost -- or this is actually a Wall Street estimate of the cost of two types of stations. On the left is a large dual-unit site, which is most of the stations in Illinois, and, on the right, is a large single-unit site, which is the posture of our Clinton station, and compare them -- this chart is comparing them again to the market prices in the various regions in 2016 forecast year. And demonstrating with the carbon adder identified it in the dotted green boxes, how much closer to profitability the stations come if that EPA assumed level of shortfall is met.

Obviously we don't yet what the final rule will say, but I think it's fair to say it will look different. At least this building block will look different, based on the amount of feedback EPA has gotten on this issue and on the importance with which it places this issue. So my main message today is I don't think we should look at the 6 percent as a limiter on what will count and what won't count when
it comes to demonstrating compliance in 2021. All zero-carbon resources should be treated similarly in a state like Illinois that has invested in this technology. It should be recognized for that investment when it comes time to demonstrate a compliance with the federal carbon program.

So in conclusion, we are pleased that EPA has recognized the important environmental and reliability and economic benefits of the existing fleet and has taken steps to create a regulatory incentive to value it. And we'd like to see whatever 111(d) compliance program develop value of the carbon-free attribute of nuclear power. Which we think is necessary to support the continued operation of these resources. Thank you.

CHAIRMAN SCOTT: Thanks. Questions?

I have a couple of clarifying questions for you, if I could. What is -- you talk about the converting the mass-based and whether or not that makes sense to provide full value for nuclear. You can set up a mass-based system that would allow some kind of trading, based on the amount
of emissions that a plant has that would value nuclear. I mean, there is a way to do mass-based program that would value nuclear.

MS. KATHLEEN BARRÓN: Oh, I think that was the point I was trying to communicate; is that it would explicitly value nuclear. You wouldn't have to come up with a way to it if you do it explicitly. And, of course, the state has the option to comply using a mass-based system under the EPA proposal at least. So there's no impediment to that. The comments are more directed at the way if you choose to use a rate-based system. That 6 percent interacts with what's at-risk and how it doesn't provide enough of an incentive really to maintain the fleet. I mean, we have over 10,000 megawatts of nuclear capacity here but the only real consequence in Jim's example of losing the amount of terawatt hours in nuclear that he posits is 150 megawatts. There's not really much of an incentive. So that was point I was trying to make.

CHAIRMAN SCOTT: Thank you for clarifying that for me. And, then, post 2030, some of things that
have been talked about nationally, in a lot of
groups -- obviously, in Jim's presentation, if you
protect everything that you've got until 2030, then
essentially it's kind of a wash in terms of what
you're docked up front for and what your credited for
in the back end. Post 2030 you go to a kind of a
rolling average of the years, so the issue of nuclear
is important past that too, and there we start to run
into some licensing and some other issues as well.

Maybe you can touch on that just a
little bit because a lot of the fleet is in licenses
that's going to expire right about that time.

MS. KATHLEEN BARRÓN: I think Illinois is lucky
that of our six stations we have two who are in that
posture that would reach 60 years around that 2032
time frame. But the rest of them are more like late
2040s, 2048, 2047. So I don't think it's as acute
here as it may be other places, but you make a good
point. I mean, there needs to be some direct -- you
need to address what happens when you have a large
amount of megawatt hours sort of going out of the
system and EPA hasn't clarified what they expect at
that point; but that needs to happen.

CHAIRMAN SCOTT: Doctor Sotkiewicz, welcome back. Good to see you again.

DR. PAUL SOTKIEWICZ: Mr. Chairman, thank you to the Commission for the kind invitation to come back here. I must be doing something right, if they'll let me back in your state. Please don't revoke my passport; I love to come to Chicago.

PRESENTATION

BY

DR. PAUL SOTKIEWICZ

I'm going to try to keep my comments brief. In the words of the late basketball coach, Al McGuire, I will try to make this last Mass at the summer resort quick, but those of you who know me know I probably won't succeed at that.

So if we think about them -- let me just kind of approach this from a broader perspective and that is from the PJM footprint. There's northern Illinois, the ComEd service territory is part of PJM. The rest of PJM is in MISO and Todd Ramey will talk about that in his remarks. We have the largest
central dispatch system in terms of peak load megawatts in this hemisphere. It's a very large system, running from the Jersey Shore effectively out to the Mississippi River with the Quad Cities' units out on the Mississippi that Exelon operates.

Nuclear -- if we're thinking about nuclear as a resource, it's about 19 percent of the total capacity in PJM but accounts for about 35 percent of total energy. And that has been very constant over time, especially with the advent of wholesale markets.

If you contrast that, if you think about coal capacity, coal accounts for actually up to or up through the upcoming delivery year accounts for the largest amount of capacity, but yet only supplies about 42 to 44 percent of total energy today. A lot of that is coal resources that will be going away with mercury or toxics standards. Currently natural gas is somewhere in the ballpark of about 16, 17 percent of total energy. That will soon become the largest resource in terms of capacity on the system. And then wind, if we're thinking of renewables along...
those lines, wind and solar and so on account for
less than 3 percent today, total energy. So if we're
talking about some of the compliance options in
nuclear, renewables and so on, nuclear certainly is
providing the lion's share of that.

But as an RTO we're independent; we
don't have a dog in the hunt. We are
resource-neutral; fuel-neutral; technology-neutral;
age-neutral, subject to reliability constraints, and
so I think here are some of the things that Kathleen
was talking about and my CEO, Terry Boston, is
talking about. Just thinking about nuclear -- just
large stations going away creates a potential
resource-adequacy problem not to mention transmission
issues. Transmission upgrades would need to be put
in place, probably in all likelihood to allow any
such resources to retire in a reliable manner.

And if we also think about
gas/electric coordination issues, and now I'm getting
a little bit into reliability; but we have to think
about reliability as we're thinking about the EPA
rules. One of the big contingencies that we're
worried about is what happens if we lose large nuclear units, they just trip off line all of a sudden? What's going to replace that in real-time operations? It's probably going to be gas. Can a gas system actually make up for that in such a short space of time? Can it maintain pressures on the pipelines and things of that nature? And we're in the process of looking at that with a lot of the other planning authorities in the East, through the EIPC case study; so, there's a results-to-be-determined. But those are some of the things that we worry about when you look at with respect to nuclear and reliability just in general, let alone if we think about the EPA Rule.

But I think before I jump into some of the aspects of the EPA Rule I want to reiterate something that Kathleen talked about, and it's the four nuclear units that did not clear an RPM. Keep in mind that this is not a market where people can simply bid anything. The offers in the capacity market are mitigated for existing resources which would include the resources: The resources in the
four nuclear units in question. And those costs have actually been closely examined by both PJM staff and also the market monitor. So we know that those costs, that the going forward costs were simply too much for those resources to clear, given the market dynamics currently in our capacity market for the 1718 delivery year.

So that being said, just sort of providing a broader background, I think in thinking about the EPA Rule Section 111(d) and even 111(b) with respect to new resources, there's four big things I want to hit on; one is reliability. I've already touched on that just in general, but one is a reliability safety valve, the idea that EPA has talked about in the past mercury or toxics standards, but that doesn't show up in the proposed rule. In some sense it's because retirements can occur, and even if nuclear stations did retire, there's a ten-year rolling average period in phase one; and, as you mentioned, Mr. Chairman, a rolling three-year period after 2030 that you can basically trade over time, banking and borrowing of emissions over time,
to comply with the rule. And so it wouldn't create an issue where we'd have to extend units per se, like we did with previous rules.

However, there's another issue that pops up that EPA has not acknowledged in the rule itself, and that is, What happens to dispatch: Real-time Operations, Unit Commitment, Real-time dispatch. And it's going to depend on what each individual state does.

Mr. Chairman, you had asked Kathleen about the mass-basis or even a trading program; there are some states in our footprint that we've talked to, that shall remain nameless to protect both innocent and guilty in this case, that have not just said no, but no way, no how, H-E-double toothpicks no -- to quote Radar O'Reilly -- "we're not going to put a price on this."

And if you have several states that choose to go down that path, remember Illinois' part of an interconnected system with both PJM and MISO. How is that going to affect pricing within the State of Illinois if Illinois decided to go down the road
as you suggested, Mr. Chairman, or a mass-based
cap-and-trade program. I think that's something to
think about in terms of that dispatch.

Then there's also the regional
compliance option. Of course bigger is better.
Regional compliance is probably more cost-effective,
that's why we have RTOs. If you look at the value
proposition that MISO offers, the value proposition
that we offer, I mean there are economies and scope
and scale to this large-scale cooperation, but also
regional compliance comes up in a multitude of
reliability senses that may be out there because the
greater the scope and scale, the more you can make up
for a lot of these potential reliability issues. But
I know you're going down that in another workshop in
November, so I will stop there.

Let me kind of dive down into some of
the nuclear at-risk issues. I think Jim has pointed
this out, Kathleen has pointed this out, EPA did in
fact, to use the words of Kathleen, peanut butter the
nuclear at-risk; but the EPA has data at their
disposal. In fact, in their modeling in IPM for the
first time they've actually included going-forward costs for all the nuclear stations in service. They could have very easily taken this going-forward cost, they could have projected revenues through IPM or even looked at revenues that these units are making today to understand which units are at risk.

I think it's very clear if you look at some of the retirements that are notable out there, whether it be Kewaunee or Vermont Yankee and then of course the catastrophic failures of units such as Songs out in California or CR3 down in Florida. I mean, those units could have potentially come back, but it was just very expensive.

Very easily EPA could have looked at this state by state and seen the units at risk and allocated things differently. They have the data available to them make that happen, whether it's our publicly available data on revenues or the going-forward costs that they've published. Then of course there's also the renewables; that issue was brought up, and Kathleen, you had opened the door in wind reducing energy prices and so on.
But it's a compliance option as with nuclear. And Illinois may be in a situation where most of the nuclear power is tied to load here in the ComEd service territory, but there're other nuclear stations very close here to Illinois that are serving load in other states. And it could be the case at some point in the future, effectively because of regional dispatch, that electrically those nuclear units also serve other states. So it's not just necessarily an Illinois problem, but it may be a more regional problem with respect to compliance as well as reliability.

And then, of course, who owns the power? Who owns the zero-emitting resources? The EPA rule in one place is silent, or is at best silent, at worst it says the renewables or nuclear should be in that state. Well, maybe it doesn't have to be in that state; which is what, I think there's got to be some clarification there in order to have a reasonable way of going forward in any sort of state plan in the final rule.

And, finally, let me just conclude
that if we're talking about rate-based versus mass-based. I think one of the things that has come up time and again in discussions with various states in our footprint, and you know, certainly mass-based is easier if you had a trading program.

I can say "trading" in here without getting shot, I think.

CHAIRMAN SCOTT: At least so far.

DR. PAUL SOTKIEWICZ: I am wearing Kevlar, just in case.

But I think, you know, I think it makes it easier to price out emissions, which also makes it not just better for the nuclear units, from Kathleen's perspective, but in terms of reaching compliance and cost-effectiveness. If we have a price on emissions and it's the same across the footprint, it actually provides a more cost-effective solution in our energy markets, and also, it's going to help enhance reliability by putting all of those resources on the same footing. Because one could imagine that some states may choose to do something different, we could end up in a situation where we
have a bunch of new natural gas units located in one state because the state decides they're not going to bring them into the program. And under 111(b) they're exempt, and all of a sudden they have to pay for network upgrades in order to be deliverable. Because they're also not paying per price of CO2, it actually is going to have an effect on energy prices. It's going to affect the revenue streams for all the resources in the footprint: Nuclear, coal, everything else that may be facing the CO2 price. Those are other things.

So whatever happens in one state, other states are going to effect it; it's just the nature of the system, it's the nature of regional dispatch, it's just the nature of working with compliance under 111(d) at this point.

So with that I'll leave it there and open it up to the Commissioners and Mr. Chairman for questions.

CHAIRMAN SCOTT: Commission Colgan?

COMMISSIONER COLGAN: Paul, you mentioned that in the PJM footprint, I think you said that natural
gas accounts for 16 percent of the capacity; is that you said?

DR. PAUL SOTKIEWICZ: Total energy.

COMMISSIONER COLGAN: Total energy. Thank you, Paul.

And you also said that it will soon become the leading -- leading source, and do you have a projection in terms of how long that's going to take. And is that just going to come in take the place of the retiring coal, or will it actually go above where coal is at now?

DR. PAUL SOTKIEWICZ: Commission Colgan -- and please forgive me, I probably didn't articulate this very well. What I was referring to was confusing capacity and energy.

Energy gas provides 16 percent of total energy, and it's right now approximately 40 percent at capacity. By the 2015/2016 delivery, which starts on June 1st, 2015, natural gas will become the largest capacity resource. It may not provide as much energy, but it's going to be the largest resource in terms of megawatts, stealing
ground in the footprint. And yes, it will be taking
over for a lot of the coal that's retiring,
absolutely.

COMMISSIONER COLGAN: Thanks.

CHAIRMAN SCOTT: Just a couple quick things
before we turn to Mr. Ramey.

In terms of dispatch, just so
everybody's clear because, you know, the rule
provides for gas an amount to be ramped up. So that
when -- we talked about this a little bit during the
last policy session, that gas plants will be ramped
up to 70 percent; but that doesn't affect your
dispatch because what you dispatch just based on
price.

DR. PAUL SOTKIEWICZ: That is correct,
Mr. Chairman.

In fact, it's interesting that, since
you bring up the dispatch issue, if one looks at the
EPA modeling efforts in IPM and -- by the way, they
actually bring in new gas capacity into the program,
rather than keeping it out, in Section 111(b) -- and
the gas-fired capacity factors in the IPM modeling
runs are similar, between 50 and 55 percent. So they
don't even reach the 70 percent that's being used to
calculate the goals.

CHAIRMAN SCOTT: Let me follow up -- thank you
for that. Let me follow up on something that you
talked about: The difference if you've got some
states doing things on a multistate basis and another
state's just kind of going it alone, bringing in new
gas under 111(b); but if they still have a compliance
issue, that may not necessarily help them out of
that. So because -- your other statement; I'm trying
to reconcile the two -- was that you're better off
spreading it out amongst -- or economically spreading
it out along a wider footprint that's why regional
dispatch works and things like that. Wouldn't that
also hold true for the states who are trying to go it
alone; just build a lot of new gas that doesn't count
toward their compliance option. They've got other
things that they would have to do, too.

DR. PAUL SOTKIEWICZ: It depends on the initial
allocation of the emissions responsibilities. But I
think in general trading programs we're talking
about, wholesale power markets or trading of emissions allowances under the old Title 4 trading program. You know, bigger is better; you're going to get more cost-effective compliance in that case or more cost-effective to dispatch.

There are some states in the PJM footprint, New Jersey and Virginia come to mind, where the actual emissions targets are less than the emissions rate of the new combined-cycle gas unit. So for states like that, that may be facing that choice, it's a no-brainer if they want to go it alone.

Now, to the extent that they bring those into the program and then can work with other states that have higher emissions rates, then there may be potential gains from trade in that case.

CHAIRMAN SCOTT: Correct.

DR. PAUL SOTKIEWICZ: But I think it's going to depend on the initial emission reduction responsibility.

CHAIRMAN SCOTT: Is there -- and just following up. You can have states where they can finally get a
compliance pathway for themselves, but from a trading standpoint, it might make sense for the companies within that state to be part of larger network as well.

DR. PAUL SOTKIEWICZ: That is correct.

CHAIRMAN SCOTT: I think that's what you're saying. I just want make sure that I had that right.

DR. PAUL SOTKIEWICZ: That is correct.

CHAIRMAN SCOTT: One more slight curve ball for you, and I apologize for this, but it seems to be a large part of it, and I know you guys are working on this and MISO is as well.

But the lack of rehearing on the 745 Order last week from FERC, and what that does in terms of demand response, because obviously that's been a part of your portfolio and states may or may not have to grapple with how to do that.

When you start to figure out the load, how do you interpret that now? As what that's going to do because that forces -- if the ruling stands, it forces a whole other set of state calculations that you've got to figure in, doesn't it?
DR. PAUL SOTKIEWICZ: Demand response in general is -- I don't view demand response in the context of 111(d) as being that big of a player. However, in terms of electricity markets and the financial wherewithal of other generation resources, especially vis-a-vis revenues potentially available in a capacity market, it is going to make a difference.

Rather than a curve ball, though, it felt like a knuckle ball.

CHAIRMAN SCOTT: Sorry.

DR. PAUL SOTKIEWICZ: I was kind of ducking and weaving here, trying to figure out where that thing was going to go.

But I think that right now we can't really comment too much on where we're going to go. I mean, we're still trying to digest everything with the vacature from the DC Circuit and the rejection from the ongoing hearing. And where do we go from there. We also, as many in this room are already keenly aware, we're facing another modified complaint in front of the Commission to get rid of demand
resources in our capacity market as well as potentially rerunning the auction for 1718.

Heretofore the Commission has been loath to rerun markets; however, this is a situation that is quite different. I have no idea what's going to happen on that. So I think it's premature for me to say anything more than just that.

CHAIRMAN SCOTT: Fair enough. Fair enough.

Sorry to do that to you.

Mr. Ramey?

MR. TODD RAMEY: Thank you, Chairman Scott. I actually have a few slides here but I don't have the remote because -- I ask for the assistance of a spacebar-presser.

MS. KATHLEEN BARRÓN: Happy to help you.

DR. PAUL SOTKIEWICZ: By the way, this is what regional cooperation's all about. I love this.

PRESENTATION

BY

MR. TODD RAMEY

Thank you, Chairman Scott, Commissioners. Thanks for the opportunity to have me
honest today to participate in this important topic of
discussion, important to Illinois, certainly
important to the other 14 states with a MISO
footprint.

What I'd like to do is just to give
the Commission an overview of the analytical work
that MISO has performed at the request of our
stakeholders since the issuance of and the draft
order in early June. I think it's important to point
out and for all of us to remember that we're still
very early in this process. We're just
three-and-a-half months away -- or since we initially
had a chance to review this draft rule.

What MISO did is we essentially
reached out to stakeholders pretty quickly, including
OMS thanks to the ICC's participation and comments
there that helped us craft a set of studies primarily
intended -- listing the early phases to allow MISO to
get some results out in support of the state's and
membership's needs as they're considering developing
their comments, which were initially expected to be
due mid-October. We've since had a 45-day extension.
We completed those early phases of our studies and released some initial results from those efforts -- just last week to stakeholders. So I'll give the Commission just kind of an overview of what the results showed.

In phase 1, we looked at a couple of things. One, we wanted to break down and take a look at each of the building blocks as proposed by the EPA. Essentially, we didn't do a lot of analytical work here or addition of MISO's or stakeholders' assumptions. In this effort we really took the EPA's assumptions, applied them to a capacity optimization planning model to really look and test the EPA's assumptions about the feasibility of achieving the certain level of projected carbon reductions that the EPA included in their plan.

The other thing we want to look at in phase 1 was this question that Paul went over in some detail in his remarks. Regional-wide compliance strategies versus sub-region. Eventually we'd like to get down and maybe even to look at some state level compliance strategies and what the implications
might be in terms of effectiveness of reaching carbon-reduction targets and the overall costs. We didn't go down to the state level, but we did look at some subregional model compliance strategies within the MISO footprint and, largely around our local resource planning zones that we use in our planning process.

In phase 2, we looked at a series of economic and public policy sensitivity scenarios. Each of the sensitivities that we looked at are shown here on this slide. Down at the bottom we did include some nuclear retirement scenarios as part of this initial phase 2 look as well. We looked at a no-nuclear-retirements; so the nuclear fleet as it exists today is preserved throughout the 2020/2030 timeframe. In the other scenarios we looked at retirements at the expiration of the current 60-year nuclear lifespans in the footprint.

So what did we find out? Phase 1 early there were a couple of key objectives. One was that implementing the EPA's four building blocks in terms of our modeling approach suggested that indeed
you could achieve the levels of CO2 reductions the
EPA estimated, within the MISO footprint. But the
more significant finding is that if you applied more
cost optimization-type strategies at least from a
capacity perspective our studies in phase 1 suggested
that you could achieve those same levels of carbon
reductions at a much reduced cost as compared to the
implementation, strictly, of the four building
blocks.

I forgot to mention so I should back
it up and mention it now, the modeling work we looked
at -- only looked at the cost of implementing a
capacity plan over this timeframe that's compliant
with planning reserve requirements. Things that we
have not looked at to date, and weren't included in
these studies, were reliability impacts potentially
of the effect of the generation fleet as it pertains
to the bulk-electric transmission system. I haven't
looked at that yet. Nor have we looked at potential
impacts to the natural gas distribution system and
new requirements on gas distribution that we are
required to achieve compliance as well. Both of
those aspects MISO's going to take a look in further phases of our studies.

So back to phase 1 findings. Looking at that the MISO region-wide compliance strategy versus a subregional compliance strategy, it's very similar to what Paul's describing. Potentially state by state, independently pursuing their own compliance strategies; that is akin to the subregional approach that we did model.

Not surprised, but the magnitude of the impact we found through our studies is that potentially if we were to pursue MISO wide strategies, cooperation across MISO for implementing economic carbon reduction strategies as compared to subregional, the footprint could stand to save about $3 billion annually from a MISO wide approach, driven largely by many things that Paul mentioned: Wider region, more options, more cost-effective options for achieving compliance; you'd expect annual cost-effective results.

Yes, sir?

COMMISSIONER COLGAN: When we looked at the
subregional zones, did you look -- I don't have my
copy here, it's not a color copy.

So did you have Illinois, the MISO footprint in Illinois as its own subregional zone?

MR. TODD RAMEY: Yes, we did.

COMMISSIONER COLGAN: Okay.

MR. TODD RAMEY: The subregional zones we
looked at are consistent with the current expansion planning and local resource zones we used for the MISO plan in Illinois as their own local resource zone.

Could we back up one slide.

The take away from our phase 2 analysis, looking at implications for the coal fleet in MISO, 11 to 12 gigawatts of coal we would expect to retire as a result of compliance with the mass requirements. In addition to that, our studies here shows that about 14 gigawatts -- 14,000 megawatts of additional coal-fired generation of the MISO footprint would be at risk to economic retirement as a least-cost solution as you move forward compliance with this draft rule.
This slide here I just want to point out the -- Slide 5, please -- I just want to point out the bottom line. That shows the results in terms of carbon reductions by the implementation and with the assumption of all of the input assumptions underlying the building block approach used by the EPA. Implementing those across the MISO region results in the level of reduction shown by the purple line, at the bottom, which is a slight over-compliance against the targets laid out in the draft rule.

So moving on to -- I think this is my final slide here. This is just taking a little closer look at Building Block 3. The green line shows the CO2 reduction expectations that you would expect, based on our modeling, from implementation of Building Block 3 using the assumptions included in the draft rule. This assumes that the existing nuclear fleet is maintained and is available throughout this region, and that the states that have RPS requirements complete those requirements. A relatively modest impact in terms of total carbon
reductions, not a large driver of carbon reductions for the MISO footprint. You would expect, just with the completion of the RPS requirements that the pie charts at the bottom reference case on the left really is a business-as-usual result in the 2030 timeframe. And those are projections by energy production to meet the requirements in the MISO footprint. The pie chart to the right shows the results, or the slight changes in production levels, with completion of those RPS standards: Slight increase to total end production across the footprint, offsetting slightly both gas and coal production.

So, with that, that concludes my opening remarks and I'm happy to answer any questions the Commissioners might have.

CHAIRMAN SCOTT: Thank you, Mr. Ramey.

What are the additional sensitivities that you all are planning to model?

MR. TODD RAMEY: We just -- just having learned about the extension, engaged just within the last week, stakeholders in conversation about what
additional studies can MISO perform given the extra
time to provide comments, we have asked questions
about additional sensitivity studies. One of those
it was pointed out would be helpful was related to
the assumptions around nuclear retirements. The
modeling we've done so far is based on the assumption
that the goal of retaining existing nuclear is
accomplished. One of the scenarios we've been asked
to look at is, if that's unsuccessful, what are the
potential implications of the cost and building need
that carbon-reduction targets certain. So that's one
scenario we're going to add in the near term.

CHAIRMAN SCOTT: You mentioned, looking at
state-by-state, is there any thought to
state-by-state versus multistate comparisons, because
I'm assuming most states are like ours, they want to
know before they get into something like a multistate
program, what the impacts of that would be for them.

MR. TODD RAMEY: We've had many of our states
already engage us in feasibility of MISO conducting
state level analysis similar to the subregional zone
analysis we completed so far. So our modeling folks
are preparing a plan to accomplish that in the near term.

I'm not quite sure I have a timeframe yet when we can get that accomplished, but I know we're working with our states to try to get some state level modeling done as well.

CHAIRMAN SCOTT: My last one. When you modeled this, did you model the building blocks individually and then do them together or did you do it all in one --

MR. TODD RAMEY: We did all those things you mentioned. So if we go to Slide 5 again -- back up one. Each of the lines there shown on the chart represent the results for modeling each building block individually. And then the last scenario was simultaneous implementation consumptions for all building blocks and that results in a total level of reduction shown on the purple line at the bottom. So, we looked at them individually and collectively as well.

CHAIRMAN SCOTT: Okay. I just want to make sure building blocks individually and then is the
MR. TODD RAMEY: It's a separate modeling run with the implementation and the assumptions for all four building blocks applied simultaneously into the model.

CHAIRMAN SCOTT: That was my question. Thanks.

COMMISSIONER del VALLE: Quick question. Is PJM's modeling comparable to what MISO is doing?

DR. PAUL SOTKIEWICZ: Commissioner del Valle, thank you for giving me the opportunity to jump in here.

We have been actually approached an organization, PJM States, to do modeling on this. We're actually in the process of doing that, and I think we've taken a slightly different tack than what MISO has taken. One of the scenarios that has been requested has been the 50 percent nuclear retirement scenario, so we'll be running that.

We're going to be doing this a little bit differently. We're running all models in PROMOD, which is a production cost software model. We're
working to endogenously determine the prices of CO2 emissions within the context of that model and take a look then at what actually is falling out in terms of compliance; how much gas is be re-dispatched, for example, how -- you know, the impact of renewables, the impact of energy efficiency. And we'll be running some sensitivities on renewable energy to plan as well as energy efficiency scenarios going forward on that. We hope to have those runs done sometime early to middle of next month.

COMMISSIONER del VALLE: So Illinois will be able to compare "apples to apples."

DR. PAUL SOTKIEWICZ: That's what we're hoping for.

COMMISSIONER COLGAN: Mr. Ramey, the modeling you're doing is using EGEAS; is that correct?

MR. RAMEY: That's right.

COMMISSIONER COLGAN: So Paul, what was it you said you were using to do your modeling?

DR. PAUL SOTKIEWICZ: We're using PROMOD, which is a production cost software model that we use in our market efficiency analysis, as part of our
regional transition planning process.

So they're different modeling frameworks and slightly different tacks, but I think at the end of the day, you'll probably come up with very -- the outputs are going to be very much the same kind of outputs that you might expect.

COMMISSIONER COLGAN: So to maintain consistency you're each using different models.

DR. PAUL SOTKIEWICZ: Did you realize we had the same problem in the modeling efforts?

CHAIRMAN SCOTT: Thank you very much. We really appreciate it, Ms. Barrón, Dr. Sotkiewicz, Mr. Ramey and Mr. Ross. Thanks very much. We really appreciate you being here. It helped a lot.

DR. PAUL SOTKIEWICZ: Thank you.

MR. RAMEY: Thank you.

CHAIRMAN SCOTT: I'd like to call the second panel up. That would be Anthony Star, the Director of the IPA, Sarah Wochos, the Co-Legislative Director from ELPC, Madeleine Klein, Senior Vice President of Policy and Strategy from SoCore, and Eric Thumma, the Director of Policy and Regulatory Affairs, Iberdrola
We're going to talk a little bit in this panel about the Illinois RPS and renewables in general. And how best to get the additional renewables into the system, and talk about DG and geothermal and all kind of other good stuff.

So with that, Mr. Star, thanks very much for being here.

PRESENTATION

BY

MR. ANTHONY STAR

Thank you, Chairman and Commissioners.

I'm going to get started, I want to give an overview of where the RPS in Illinois currently stands and my fellow panelists will probably go into a lot more detail about the challenge it had and some of RPS' potential solutions.

So if you ask around, the common rhetoric you hear is the Illinois RPS has the goal to finance 25 percent by 2025 and that the goal for next June will be 10 percent. Sounds very good. The reality unfortunately is a little bit more
complicated, but I'll look at it a couple of different ways. The first is that if you look at renewables as a percent of generation that takes place within the State of Illinois we are at about 5 percent in 2013. So of the energy produced in Illinois -- if you think about what Jim was talking about a lot of his numbers on nuclear really were focused on production in the state. That puts us at about fifth in the nation in terms of the amount of generation that takes place within the state. But we are 19th in this nation in terms of renewables as a percent of our total generation. That's in part a reflection of the fact that we have a lot of conventional generation in Illinois. We look at all of the states that have a large renewable -- a lot of renewables in them. They simply just have a lot less conventional generation.

Take Iowa, for example. They have 50 percent more renewables than Illinois, and those renewables, however, make up 25 percent of their generation. That's basically because we use about three times more energy in Illinois than Iowa does.
So you have some interesting mismatches when you look at the different generation rates of renewables.

That's really relevant when you think about the future need for renewable construction and how it will impact the generation mix in any given state. I think the amount of existing capacity in Illinois will really have an impact on prices because renewables will have to compete against those.

But when you go turn to our renewable portfolio standard we measure that as a percentage of consumption and in large part because of these issues with regional transmission. Power doesn't really obey state lines. Maybe it would be a lot simpler for a lot of us if it did, but I'm not an engineer, but I'm pretty sure that would be hard to do unless we cut a lot of lines.

So it's really hard to tie consumption of any one customer to the specific source of generation but it's a lot easier to think about renewable portfolio standards from the consumption point of view. And that does seem to me to create a little bit of disconnect about how we think about the
RPS versus some of the other aspects of how we were
to comply with Clean Power Plan.

I would also note that when talking
about the RPS, I'm only going to be talking about the
two large investor-owned utilities in Illinois.
Municipal utilities are all co-ops armed subject to
the state RPS. They're only a small percentage of
the total of the state, but we still should keep them
in mind because this is ultimately a state plan and
some point or another have to be able to think about
how they get involved -- adding that to the others.

When you look at the RPS in Illinois
the reality also is that we really have more than one
RPS. The original RPS that was passed in 2007
applies to the traditional utilities and the
customers that they serve. And that is done through
two different ways; there's a compliance mechanism
for customers who are traditional flat rates and then
also a separate mechanism for customers who are on
hourly pricing, who pay into a fund rather than have
their renewable commitments covered by a rider.

The utility RPS commitments are done
through commitments done by the IPA. In the history of the IPA -- well, it got started in 2008, we've done one large long-term renewable procurement back in 2010; that's about 1.8 million megawatt hours a year for the next 20 years. And that mostly came from new developments. That was a long-term commitment for large amounts of resources and a lot of new stuff got built because of it.

We've also done a number of procurements for short-term renewable resources. The most recent of those took place in 2012; we would buy renewable energy credits going out a couple years. Those deliveries from the 2012 procurement run through 2017, and each year has slightly different targets.

So right now the utilities are on track to meet their overall RPS and wind requirements based upon those past procurements. However, where they're short at the moment is they'll need additional resources to be procured to meet the specific solar generation cutouts in the RPS. We will be filing with the ICC our 2015 Procurement Plan
next year, it will contain some proposals to help meet those targets.

Mode migration has really been a major impact on the ability -- IPA's ability to procure long-term resources. Take for example those long-term procurements that actually had done back in 2010. At the time that was all hashed out -- I think there's some people in the room have scars from all those debates including some at this table -- retail competition hadn't really taken off. The utilities were basically serving 99 percent of the residential and small commercial customers. So 2010 when IPA was considering those long-term procurements, they were going to secure a lot of renewable resources for the future, but not enough to meet the RPS going forward.

Now if we look at it, what's happened is we've gone from the 99 percent or whatever it was to -- and the utilities only serving about a third of the residential and small business customers -- actually a little less than that.

So right now if you look at the RPS targets for next year, those long-term contracts for
2010 are meeting 90 percent of what's needed for next year and the short-term procurements from 2012 actually filling up the gap. So because there're so many fewer customers in the utility pool, the long-term commitments made several years ago are a much bigger portion of the mix of renewables than I think many people thought they would be at the time.

So uncertainty of that future level of load that'd be served by the utilities versus alternative suppliers makes it very hard for us to plan a long-term commitment to acquisition of new renewable resources.

I'll turn back to the other half of the RPS, which is how the alternative suppliers comply with it. They do it in two ways: First, they make, payments, known as alternative compliance payments, into the Renewable Energy Resources Fund. That covers about half of it -- a minimum of half of the obligations. Second, they have to buy additional renewable energy, typically in the form of renewable energy credits. That's the rest of their obligations.
So a few observations about what they're doing. The first is that the rate of alternative compliance payments are much higher than the current price if you want to go out and buy a RECs. So what we're seeing is that the supplier is very, very rarely making anything other than the minimum of 50 percent. It's much less expensive for them to go out and buy RECs for as much of their compliance as they can.

One challenge that that seems to create is any given supplier, year to year, their market share will vary. I suppose they all hope it will go up every year, but that's not how competitive markets work. So they don't really make long-term investments. As far as I can tell, they're mostly buying RECs on a fairly short-term basis from the market, and that's not really incenting a new generation, it's just the most efficient way for them to comply with the statute.

That raises, of course, the Renewable Energy Resources Fund, which has been discussed a lot -- I suspect will be discussed a lot more. It
has had some dire years in its youth. While this
spring, we were very fortunate that legislation
passed that will free up $30 million of that fund to
begin investing in solar resources starting next
year, the Fund currently has over a $120 million
dollars in it, and those are funds that are not being
spent right now on real good resources. Hopefully
they will be in the future.

So to tie that back to the Clean Power
Plan, if you look at the numbers from the U.S. EPA,
they're expecting renewables in Illinois to grow from
8.3 million megawatt hours in 2012 up to 17.8 million
megawatt hours in 2029.

In the short-term, let's put it on
track. In 2013, the generation made in Illinois was
about 9.6 million megawatt hours. So the numbers are
all looking okay at the moment. But absent a change
in structure, I'm not sure how we really expand this
to going forward without some new path for long-term
planning.

There has been some encouraging news
recently. Both IKEA and Microsoft have announced
investments in wind farms in Illinois. That private
investment is a good thing and hopefully we'll find
ways that gets counted toward our compliance. But we
really will need to look at how we adjust our RPS
mechanism in the fact that we have a robust retail
market. The market and allowing people to choose who
they buy electricity from, having the competition
that we have here, has had a lot of benefits from
customers in terms of very competitive prices from
Illinois.

Back in the 80's, the reputation was
that we had some of the most expensive electricity in
the country. We're not the cheapest, but we're down
in the bottom in terms of electricity prices. So
that's benefitting customers. The ability for
customers to shift their load around between -- for a
small customer between the utility procurements done
by the IPA, where there are alternative suppliers, or
even between different alternative suppliers makes,
any of this long-term strategy planning for new
acquisition of renewable resources really difficult.

So I'm encouraged by the fact that
substantial renewable resources have been built in Illinois. It shows that when we get the policy pieces aligned, we can do it we've done it on scales that really have produced some big impacts. But we need to get things corrected that to allow that to happen again. And I'm hopeful that starting next year, we'll start moving forward and expanding our solar industry. So you'll be hearing more detail from the other panelists, but we really do need to make major changes in order to get out renewable energy strategies to meet the goals of not just the Illinois RPS but the Clean Power Plan.

COMMISSIONER COLGAN: Thank you for that, Anthony. I don't want to get off track here; I know you're talking about energy efficiency issues and renewables.

I was wondering where we are at with compliance for demand response in Illinois. And now that we've got this 745 Decision that -- this has become a really big issue and a lot of focus going toward states in terms of their ability to do things in the area of demand response. We have --
MR. ANTHONY STAR: Unfortunately I don't have a solution for you yet. I think we're going to have to rethink a lot of aspects of demand response going forward.

The IPA, we have the challenge that we serve the eligible retail customer -- the potentially eligible retail customer, the residential/small business customers. Demand response for those customers is largely things like air conditioning, recycling programs. We have things in place due to the Smart Grid legislation of a few years ago for things like the peak time rebate. We may have some pieces in place but we have to rethink those solutions in terms of how that larger customers can continue to get the value of demand response in light of the recent rulings. I think there's a big challenge ahead and I don't have really good solutions yet.

COMMISSIONER COLGAN: So in your opinion do you think for Illinois to move further in that direction, we would need additional statutory authority to do that, is that --
MR. ANTHONY STAR: That would be my educated
guess.

COMMISSIONER COLGAN: Thank you.

CHAIRMAN SCOTT: Going back, following up on
something that you had talked about with the RPS,
basically saying we need some fairly major changes
without placing value judgments on any individual
piece of legislation, but the legislation that was in
front of the general assembly before, just in terms
of whether or not it addressed the issues that you
laid out that --

MR. ANTHONY STAR: Are you referring to 70103
from last year, the various versions of it?

It seemed like it was heading the
right direction because what it was creating -- well,
they're different versions of it. The final version
that -- I'm not sure it was -- I can't remember that
it was ever actually introduced but some of it was
drafts, floating around. It did create balancing
mechanisms between the different revenue sources for
renewables. And that would have allowed for a path
forward in terms being able to do some long-term
things.

Right now, I'm just very cautious about how to make a commitment with a fund that its balance could vary greatly -- not the balance, the amount of money coming into it; it varies greatly from year to year. I don't want to create new stranded costs. We have done that before, it's not fun.

So I think the concept of having a way to be able to balance these so that the net effect is that there is a consistent source of revenue for new renewable generation is a good sound one. I think we had pieces of it floating around the legislation a year ago, but obviously we didn't have to test whether or not those actually worked because it didn't get enacted.

CHAIRMAN SCOTT: And does it make more sense, given what you just said and what you said in your earlier presentation, to have something that focuses on some long-term assets as well rather than just having people out in the market buying RECs?

MR. ANTHONY STAR: It depends on what your
goals are. I mean, if you wanted to meet just the
letter of the law in Illinois buying renewable energy
then it's --

CHAIRMAN SCOTT: I'm talking more in terms of,
trying to imply --

MR. ANTHONY STAR: But if you want to look
at -- when I look at what the U.S. EPA is asking
states to do and try to figure out how that
corresponds, I see a disconnect. So I think moving
more towards something that makes sure that there's
tangible assets operating and actually providing
power for a long-term solution, that would be
preferable.

The renewable energy credit market's
been a very useful proxy in the short- to medium-term
to allow there to be investments in renewable energy,
help it get started, but ultimately it
doesn't -- there's some pieces missing.

CHAIRMAN SCOTT: I appreciate that.

Commissioner del Valle?

COMMISSIONER del VALLE: Quick question.

What's the projected coffer of for the
Fund for this fiscal year?

MR. ANTHONY STAR: This was a big year for it because switching rates have -- were quite high last year so approximately -- the last few stragglers are still trickling in but -- new revenue that has come in the last month or so for the Fund was about, $77 million dollars. Next year will probably be comparable. It may start to taper off a little bit from that if customers start coming back to utility service from --

COMMISSIONER del VALLE: So next year the balance will be approximately what?

MR. ANTHONY STAR: So we're up at $120-something, another $60 to $80 million might come in next year, and then may shrink from there. We're obviously going to spend $30 million of it thanks to the legislation that passed this spring. Still, we're talking about a pretty large pot of money that will be available for renewable energy.

COMMISSIONER del VALLE: Okay. Can you tell us how we can borrow from it?

MR. ANTHONY STAR: They -- let me choose my
words carefully. They have borrowed from it once in
the past and they've repaid it all. They do not
sweep -- they cannot sweep.

COMMISSIONER del VALLE: They cannot
sweep --

MR. ANTHONY STAR: They cannot sweep it but
they can borrow from it. My understanding in the
past is what they do is they look at uncommitted
funds in a variety of funds across the state. So for
example, if we have money committed for the new solar
procurements, that would be money that they would not
seek to borrow. Obviously they don't want to impinge
on contractual obligations that the state has made.

CHAIRMAN SCOTT: Thank you, Mr. Scott.

Ms. Wochos?

PRESENTATION

BY

MS. SARAH WOCHOS

Thank you. Sarah Wochos with the
Environmental Law & Policy Center. My name is not at
all phonetic so I've been instructed that it rhymes
with hocus pocus.
Anyway, moving on. So this is just what I'm going to cover today, so we can move on to the next slide. So in order for EPA to come up with baseline and final targets for each state based on basic assumptions that they then applied across the board. I think the term used was "peanut buttered." They likely did this for consistency reasons but in Illinois' case this methodology underrepresented the potential for renewable energy. First, to create our adjusted state baseline they included all megawatt hours from existing renewable resources within the state regardless of REC ownership. They did not include assets out-of-state that we contract for as a result of our RPS.

This baseline is important because it is a set a numbers that the EPA uses to then determine our interim final goals, and, therefore, how much they think Illinois can rely on renewable energy to meet out goals.

To create our interim and final targets, they use the average of all the RPS policies in our region to create a regional renewable target.
They then calculated the annual growth necessary to meet that regional target and applied it to every state's renewable energy baseline.

In our region, which includes most of the midwest, the regional goal is for renewable energy to be 15 percent of our generation by 2030, which will require 6 percent annual growth per year between 2017 and 2029. When that growth rate is applied to Illinois' baseline, we end up with a target of 17 million megawatt hours of renewable energy, which is equivalent to 9 percent of our generation.

So, what does all that wonky gobbledygook mean? It means the EPA targets are off by almost half. Our renewable energy standard requires us to meet 25 percent of our consumption with renewable energy by 2025, but if we use our RPS effectively, we will consume 32.5 million megawatt hours of renewable energy by 2025 and beyond; which since we generate more than we consume, amounts approximately 17 percent of our current generation.

So EPA's assumptions on our potential
for renewable generation are very low. If we use our RPS effectively we can count on renewable energy to get us even closer to our goal than they assumed. At the last policy meeting, we heard from witnesses the potential problems of counting on Building Blocks 1 and 2 for significant carbon reduction, but thankfully the underrepresentation of Illinois' potential on renewable energy will make up much of that deficiency.

The EPA has asked for more guidance in their renewable energy sections of the rule than in other sections they've left some open questions. I'd like to go over those now, but I note that at the outset that even these open questions don't diminish the potential of the RPS to help us meet our goal. Renewable energy is treated differently because we will be able to count, at least for the draft rule, actions taken before the release of the draft rule and any actions taken between now and the start of the compliance period.

As you can see, Illinois has had strong renewable energy developments since 2007 that
was at least initially caused by our RPS. For the first four years we only bought in-state RECs, which drove development. Today we buy RECs from a broader geography, and, therefore, don't necessarily have ownership of all the RECs generated by those in-state projects.

So the first open question is how to claim the carbon credits from renewable energy, whether through the location of the generation or the ownership of the REC. This is significant because it addresses the problem of double counting. If the final rule will only let us not count in-state generation regardless of where the REC goes, then we will get the benefit of some generation that is currently under contract or built in the future by other states. In the same vein we would not be able to count out-of-state assets currently under contract as a result for RPS. This situation increases the probability for double counting of states that choose different compliance pathways, rate-based versus mass-based. Therefore, we believe that compliance should probably be measured with RECs rather than the
1 power. To hedge our bet, Illinois should focus on
2 using our RPS to contract for cost-effective assets
3 in Illinois. This avoids any possibility for double
4 counting and guarantees that our purchases will be
5 compliant with both the RPS and Clean Power Plan.

So the second open question is how
7 carbon reduction for renewable energy should be
8 counted. There are actually three open questions
9 here.

10 First, whether to add the renewable
11 energy megawatt hour to the denominator or to
12 subtract the carbon savings from the numerator.

13 Second, if the carbon savings are
14 subtracted from the numerator, what is the value of
15 the carbon reduced renewable megawatt hour? Should
16 we subtract the carbon equivalent of the fossil
17 emission rate, the average generation emission rate
18 or the marginal emission rate?

19 Third, should it be the carbon
20 emission rate from the state where the generation is
21 located or a regional rate. And what is the region?

Above, you see different options of how a region can
be defined. EPA leaves this open as well.

All these options change the way renewable energy is valued in a compliance calculation. In ELPC's opinion, and the goal of the carbon pollution standards are to reduce carbon. Therefore, it is probably more appropriate that the calculation should subtract reduced carbon from the numerator to encourage development in carbon-intense areas.

If Illinois focuses the RPS on developing cost-effective renewable energy in Illinois, we are poised to win either way. Because we have some of the highest emission rates in all of these situations.

A third open question is timing. Renewable energy actions that were taken before the rule was released and between now and the start of compliance will count, provided the carbon benefits attributed to those actions happened during the compliance time period. This means that the age of the renewable energy project doesn't matter, but the vintage of the REC. This is good news for Illinois
because it means we can plan to use our RPS as an effective glide path to compliance.

In the chart above we see that the amount of renewable energy currently being generated nationally will not be enough to cover even year one of national carbon compliance let alone year 2030. So if we wait to invest in renewable energy there could be scarcity issue, which could negatively affect compliance. Even if somehow other states don’t choose to use RECs for compliance, their RPS policies and voluntary markets will still force the retirement of most of the RECs from existing projects. To secure our own future, we should hedge by investing in incremental annual purchases, starting now.

On the issue of banking RECs generated prior to 2020, the ELPC is unopposed. Banking would essentially allow RECs produced between 2014 and 2019 to then be retired after 2020.

Carbon emission and energy generation happen in real time. The only RECs that should count are RECs created in the compliance year. Project age
shouldn't matter but REC vintage should. If the EPA had intended for banking to be allowed, they would have adjusted their goals accordingly.

So, what can we reasonably expect from a fully functional RPS and how does it affect our goal? Using a measured approach to RPS compliance that allows incremental growth in wind and solar, we willfully realize our goals of purchasing at least 32.5 million megawatt hours of renewable energy in 2025 and beyond. Advances in technology and continued price reduction, especially in solar, will help us get there more cost effectively. But an effective RPS is the critical component in achieving this goal.

If we focus on our RPS -- focus our RPS on building our purchasing renewable energy in Illinois, we reasonably expect to achieve a significant portion of our carbon reduction goal. In the chart above, I've modeled the impact of subtracting different carbon-saving scenarios from our base fossil rate. The rates I've modeled are the Illinois fossil rate, the Illinois adjusted rate, a
marginal fuel rate and the average adjusted rate for
the region as defined by the Clean Power Plan. In
the worst case scenario, renewables get us 62 percent
towards our goal, and in the best case renewables get
us 88 percent towards our goal. If we include the
emission reductions from energy efficiency we can
easily and cost-effectively achieve our goal.

So how do we make our RPS an effective
policy to meet our goal? Well this is the current
situation, as you can see, it is very complicated.
For developers in renewable energy, complexity equals
risk and risk usually increases costs. In order to
effectively use the years, which we now in the start
of compliance as well as those after compliance, we
have to get the RPS back to a situation where there
is predictability and certainty. Predictability and
certainty allow for cost-effective incremental growth
in long-term planning.

The only way to achieve predictability
and certainty is to is to revamp the RPS into a
policy that groups all customers together and treats
them equally in terms of compliance. The easiest way
to do this is to make compliance a component of
distribution, not supply. Distribution companies do
not vastly change their customer load like suppliers
do and this provides stability. The IPA will be able
to predict with confidence the customer load covered
by the RPS well into the future, and could therefore
reasonably plan for incremental growth to get us to
cost-effective compliance. I believe Eric and
Madeleine will probably delve a little deeper into
what this means for their industries.

So in conclusion, we believe that the
potential for renewable energy in Illinois far
exceeds the estimated carbon benefits prescribed to
it by the EPA in Building Block 3. Furthermore, we
already have the skeleton of the policy needed to
realize those savings. However, the RPS must be
modified in order to achieve those carbon reduction
benefits. We believe that predictable incremental
growth in Illinois, renewable generation coupled with
energy efficiency, is the most cost-effective way for
us to achieve both our RPS policy goals and our
carbon reduction goals.
CHAIRMAN SCOTT: Thank you, Ms. Wochos. Questions?

COMMISSIONER COLGAN: Yes, you get the same question I asked Mr. Star.

MS. SARAH WOCHOS: Yes?

COMMISSIONER COLGAN: So the framework of the legislation that was out there before, is that --

MS. SARAH WOCHOS: It's still -- in the slide I have about complexity, it still provides a lot of complexity and there is still some risk associated, so it's not ideal. It would have gotten us towards a path where there was a little more predictability or a little less risk but it's still risky. So it was not ideal.

CHAIRMAN SCOTT: So what would the kind of changes that would need to be made? What would those be, what would that look like?

MS. SARAH WOCHOS: Well, one of the reasons why our entire energy efficiency policy is so effective is that there's a predictable amount of money and a predictable customer load every single year, year in
and year out. And so that would be the optional way for us to treat our RPS.

CHAIRMAN SCOTT: Okay. Thank you, very much.

Ms. Klein?

PRESENTATION

BY

MS. MADELEINE KLEIN

Okay. Thank you.

So I'm just going to briefly kind of walk through solar and the role that it could play as a part of Illinois' plan. I'm going to start with a brief bio of SoCore only because it illustrates both of some of the opportunities and challenges that solar has in serving as a part of this plan.

So we were founded by two Chicagoans in 2008. We were acquired by Edison International, which is one of the country's largest energy holding companies, in 2013. Edison International is one of many large energy holding companies that has either recently invested or is out shopping for distributed solar companies like ours. We operate specifically in the commercial/industrial space. There's other
companies that are out shopping for residential installers as well. We're up to 65 full-time employees in our downtown Chicago office but we've literally got hundreds of workers on rooftops right now, across the country installing our solar installations. We're in construction right now for 32 megawatts of solar rooftop sites for clients including: Walgreens, FedEx, IKEA, Kohl's, Cinemark and other household names. We're building in California, Texas, Connecticut, Massachusetts, New York, Delaware, Maryland and Utah right now, today. But the most important number on this slide is actually "zero." We have zero projects currently under construction in our home State of Illinois. So, why is that? For a lot of the reasons that Sarah and Anthony have just gone over. Illinois currently ranks 27th in our particular space in the solar market in commercial/industrial sector. It's behind every other state with a solar or a DG carveout in their RPS laws. There're two exceptions to that, one is the State of New Hampshire, which has a tenth of the populations of the State of Illinois,
so it's just much smaller. The other exception is South Carolina and they just passed their solar carveout this summer -- actually last session, so very recently. Those are the only two exceptions. Every other state with a solar carveout is well on the way to significant solar as a portion of their raw energy demand.

COMMISSIONER COLGAN: How many states that have that?

MS. MADELEINE KLEIN: Around -- in the low 20's, I think. There are solar carveouts or other kinds of solar goals, not every state does it the same way.

You know, the reason for that is really the complexity that Sarah has just outlined. Our RPS is really not functioning as it should right now. So, all in all to say there's a lot of potential there, both in the law and in the market. So solar -- Oh, sorry, can you flip back to the previous slide -- Solar in general has growth projections at about 10 percent of annual growth rate through 2030. That's Bloomberg New Energy Finance's
sort of base case for the projections for solar market growth over the next 15 years or so. Now, solar has been well overshooting anybody's projections for the last eight to ten years or so. So I'm guessing that this is actually -- we'll look back to find that these were pretty conservative numbers. The market dynamics are in place for strong growth, so the question becomes, what will it take for Illinois to really share in this growth and make it feasible for solar to play a large role in our carbon reduction plan?

So to answer that question -- you know, the next question is, well, what makes a viable solar market? And just like any other energy resource, the levelized costs of solar installation have to be less than the levelized returns over time. This is pretty simple, but you know, what's different here, for solar versus other types of assets is that costs are compressed over time through economies of scale, barrier reduction, market competition, and primarily declining equipment prices.

The costs of solar installed capacity
have been declining very dramatically, especially since 2008/2009. The expectations are that that very, very steep decline that you can see in that chart may start to level out a bit, but the general trend is going to keep going down there. So over time, costs are compressed, returns go up as the value of that solar energy increases which means that ultimately the state incentive that was necessary to close that gap diminishes and ultimately gets on the path to zero.

In a state like Illinois where the energy value -- energy prices are relatively low, it'll take a little bit longer than some other states for that state incentive piece of it to diminish to zero, but ultimately that's the directional trends that we're heading in.

Go to the next slide. My animation is not happening.

So what are the smart ways to close that gap? What are the smart ways to design state incentive program that really does the job of allowing the state incentive that is necessary to
close the gap, to decline over time? Before we would talk about it, the first thing we need to do is fix the RPS in the way that Sarah and Anthony sort of described and hinted at. That's Number 1. Once we've done that, we'll highly re-structure it to really work out well.

There's two basic models that are at work in markets across the country that we can consider adopting here. One of them is a competitive market-based type of program that values the extracts of solar installation. Lots of good models out there for programs that work very well; they're all a little different, I won't go into the details. The advantage of a competitive market-based program, of course, is that projects receive just enough but not too much of that incentive funding to get them over the economic threshold and allow projects to go forward. So this is arguably the most cost-effective type of program to set up.

The other program design-type that is very common is what we call a declining megawatt block type of program. And that just simply says
we're going to offer an incentive at "X" price for a
certain amount of capacity. Once we fill that
capacity block, the incentive declines to the next
lower level. We fill the next capacity block, the
incentive declines and so on and so on.

So California's solar initiative is
the longest running solar incentive that exists in
the country today. It's the biggest, they've
developed about 1.8 gigawatts of power under this one
particular incentive program. Of course, California
has other ways of incentivizing solar. But you can
see on the chart on the right side of the slide,
costs have been declining very steeply in the context
of this incentive program over time.

So the advantages to this type of
program are transparency, predictability, even the
administration. So you could say, Well, does that
make up for the fact that maybe the prices aren't
precisely efficient for every single project. You
know, there are debates about that, but arguably,
they do.

Ultimately: you fix the RPS; you
solve the problems that were outlined by Anthony and Sarah; you set up an incentive program, people will come. There will be a solar market that gets developed in Illinois. You know, we get a lot of questions about, Well, is it sunny enough? Is it -- you know, blah, blah, blah? Yes.

You solve the policy problems, the solar market will develop. The essential program features for getting this done, you need long-term contracts with financeable terms. When I say "long-term," I'm not talking about 20 years; five years is just fine. So hopefully that avoids some of the historical issues that we've had with long-term contracts in Illinois.

You need a sustainable multi-year program. So the $30 million that the legislature freed up in this past session is great, we're excited about participating, but it doesn't really get us the consistency that we need. You need to allow companies to really invest in people in Illinois. Set up shop, hire workers, do that kind of work so that we can create jobs here.
It needs to be transparent, predictable and large enough to matter. To really attract the kind of investment that we need, it needs to, you know -- it can't be a couple million here and there, it has to be large enough to get people here to really set up and invest.

So, finally, you know, benefits -- clearly carbon and other pollution reduction is very, very significant. Again, the cost-effectiveness of those pollution reductions gets better over time as prices come down. We've got lots of grid benefits: distributed solar in particular, in terms better resiliency of the grid; avoiding line losses; being able to defer some T&D upgrades that would otherwise would have to happen.

And then, finally, jobs and economic investment is very significant. These are jobs that can't be outsourced; installation jobs happen in state. Just a couple highlights to share from the Solar Job Census that was put out by the Solar Foundation. By the end of 2013, there were many more people employed in the US solar industry than in the
coal and gas industries combined. We're up to 140,000 people employed. Year-over-year job growth is up in the 20 percent range, so that's quite a lot higher than the national average. At the same rate, fossil fuels jobs declined significantly. So these are just some of the ancillary benefits that we can achieve by making solar a very significant part of the carbon reduction plan going forward.

COMMISSIONER COLGAN: I hear the theme and I've heard for a couple of years running now, as to we need changes of the Renewable Portfolio Standard. I'm just wondering, is there existing authority that could be used to deal with some of this? And is there some authority that you might think that this Commission would have in terms of helping advance your goals that is not being taken care of.

MS. MADELEINE KLEIN: It's a good question and I might defer to Anthony on thoughts on this. But in my mind, the primary sort of sticking point is the funding mechanism. You know, how do you free up the funds that are necessary to incent solar development.
If we could do that in some other way outside of the RPS, then potentially that would be a good solution.

The RPS is preferred -- fixing the RPS is our preferred approach because it does have the promise of a long-term consistent policy and funding source that can be put to work growing an industry over many, many years.

COMMISSIONER COLGAN: And the declining block system that you talked about, you set a goal for how much you want to get done at a certain incentive rate.

MS. MADELEINE KLEIN: That's right.

COMMISSIONER COLGAN: And once you've met that there's the next block that you go to with less incentive until you eventually get it down to zero.

MS. MADELEINE KLEIN: Yes.

COMMISSIONER COLGAN: And you say California is a making that system work?

MS. MADELEINE KLEIN: Yeah, they're making that system work and in fact, there are three big IOUs in California: PG&E, Southern CalEd, and then San Diego Gas&Electric. PG&E has run of out of incentives;
they've gotten down to zero; they've used all their capacity. They're still solar developments going on in PG&E territory, it just doesn't need to be an incentive market anymore. The other two utilities are on the very last step of the program.

COMMISSIONER COLGAN: Is the sun better in California than it is in Illinois? Is that part of the reason?

MS. MADELEINE KLEIN: You know, yes, the sun is better in California than it is in Illinois, but I would say that's not part of the reason. I mean, certainly marginal generation efficiency is a part of the equation. You know, there are other parts of the equation; the cost of energy is a very significant policy structure. So the three things together are three factors that interplay with one another to determine the viability of any given market. So New Jersey's the second biggest solar market in the US after California, and New Jersey's sun is not as good as ours.

COMMISSIONER COLGAN: I guess I'm kind of struck by the number of jobs that you talked about.
And a couple parts to the questions there, what -- are the skills that people need to work in the solar industry a different set of skills that you would need to work in, like the gas and coal industry? And, to what extent has anybody measured -- I know that in the President's Recovery Plan, he had a lot of green energy pieces in there. And the whole idea was that people would be employed on a temporary basis, to do these jobs and that they leave that period of time when that -- those resources were available and then be able to transfer that into unsubsidized jobs.

Are some of these people -- was that affected in your opinion, or do you have an opinion on that?

MS. MADELEINE KLEIN: Well, let me start out by saying that the types of jobs that are active in the solar industry are electricians. Of course, we've got laborers who haul panels and haul racking systems up to the roof; we've got folks who are connecting conduit; we've got crane operators who are hoisting things. You know, it's mix of a number of different
kinds of construction and electrical trades.

So the way that ultimately the President's goal was supposed to work out, I think has been successful in a number of ways, you get these folks trained up to do solar installations. Yes, it's -- a solar installation has, depending on the size of it, maybe you've got a bill period of a month or two months or three months, and then those people move on to the next job, right? There is a certain amount of ongoing operating and maintenance work that needs to be done on solar installation, but primarily you hope that those people get employed in the next job, in the next job, and in the next job. And I think that there's really good argument that that will happen given the -- on average 10 percent compound annual growth rate that we're seeing in this market today.

COMMISSIONER COLGAN: Okay. Thank you.

COMMISSIONER del VALLE: I have a question on the jobs issue.

How much -- I know you're dealing with commercial here, but what's happening with
residential? I mean, how much of the activity is in that column and how does that translate into future job growth, also?

MS. MADELEINE KLEIN: Yeah, the residential market is even hotter than the commercial/industrial market right now. We're not in that sector, so, I'm not an expert on the data there. But I will say that the growth trends in residential have outperformed commercial and industrial for a couple -- for at least the last year or so.

COMMISSIONER del VALLE: And the incentives for residential, how do they compare in California and Arizona and other states?

MS. MADELEINE KLEIN: So there are incentives for resident -- there are incentives for residential just like there are in the commercial/industrial market. Typically residential systems, just because they're so much smaller, are more expensive on a per-watt basis than the larger C&I type of systems. However, the energy offset rate of a residential customer is typically higher than the energy offset rate of a commercial/industrial customer. So that
tends to balance that out a little bit.

Incentive programs for residential sectors specifically, more often than the commercia/industrial sector, have been designed as an up-front incentive, so you get a certain portion of the system price bought down by the state incentive rather than having it paid out over time in the sort of model that we've been discussing here. It can work either way and there are different advantages and disadvantages to either program model. But it's safe to say, again, if we fix RPS -- take the time to design a smart procurement, a smart program here which Anthony has been doing, for this initial procurement, we'll absolutely be able to get the residential market up and running as well.

CHAIRMAN SCOTT: Thank you very much, Ms. Klein.

MS. MADELEINE KLEIN: Thank you.

CHAIRMAN SCOTT: And Mr. Thumma, can we hear a little bit about wind?
PRESENTATION

BY

MR. ERIC THUMMA

Good afternoon and thank you for the invitation to join you today. My name is Eric Thumma and I am with Iberdrola Renewables. We are a developer/owner-operator of -- primarily of wind, we do have some solar assets in the western part of the country. This is just my overview of my presentation. Some of this will be redundant with the other speakers so I'll try to make points that were maybe different or complimentary to what they were saying. The main point that I'm going to attempt to make today, though, is to show you that the policy we already have in place in terms of the wind requirements within the RPS, can get you a substantial way to the 111(d) goal, if implemented properly.

So we've talked about some of this but I'll just make a few points. 111(d) is going to require real reductions and I contrast this to my time at the Pennsylvania DEP when we would implement
some programs, for example, ground level ozone where EPA would give us credit just based on doing something. So gas caps -- central gas caps come to mind, vehicle emissions inspection comes to mind; this is not going to be that type of program. EPA is going to measure actual carbon emissions. And so in terms of using RPS as a building block to getting there, we have to make sure that RPS is actually leading to real investments in the ground that are offsetting emissions of carbon dioxide, and that this isn't just an accounting mechanism. That has been one of the problems with RPSs across the country, is that they tend to become accounting mechanisms in some instances for unbundled RECs from existing facilities or facilities that didn't really need a financial incentive and that those facilities already existed and didn't change emissions baselines of those states. So that's where we are and I think that's important to remember as we construct the RPS going forward.

In anticipating your question about load shifting -- so I think load shifting is really
the main challenge with the RPS. And it's unique to Illinois because of the way the Illinois RPS is created. So to anticipate your question, I would say that our industry, and certainly our company, preferred the solution inside the 103, which was to make the RPS compliance a function of distribution charge. We felt that was the simplest mechanism; it had the potential to be the most transparent and it also is competitively neutral. So competitive suppliers can still go out and compete with each other for brown power and complete on generation; we weren't affecting that market. And then further, they could still offer green products that were over and above the RPS. So we thought that was a solution that really addressed all the potential challenges.

That said, if that's not workable I think some of the other ideas that were put forward, are things that we would be interested in talking about. I think the key is, as all the folks here have demonstrated, is that we have a stable, known stream of revenue that the IPA can use to make what they believe to wisest investments, the most
competitive investments.

I think the last point that hasn't been touched upon in terms of RPS reform is ACP. You have this unique ACP mechanism in Illinois. I think EPA has been fairly clear that ACPs are not going to count as reductions. So obviously, you can take the ACP and you can invest it in a way that makes reductions in certain projects that will be making reductions, but I think it may be prudent to look at, is that adding a layer of complexity that's unnecessary and can we change the RPS to make it more efficient. So I would sort of offer those two points: Distribution charge as the function of RPS and looking at the ACP as a way to dramatically improve the efficiency of the RPS as we consider it in the context of 111(d).

So I'm just mixing in some AWEA slides that will give you a natural picture. I won't dwell on them. This is just sort of showing carbon reductions from wind energy, just to sort of emphasize that wind is working, reducing carbon dioxide right now, and it's a policy that I think EPA
has rightly inserted as one of the main building blocks.

Try to look at Illinois, specifically, and these are my projections, so I will happy to provide all the data behind this if somebody is interested in looking at it. We actually filed these numbers with the ICC in the last year's IPA proceeding in rehearing that we did. So I think these may be a little conservative than some of the other numbers that you've seen; largely because I'm only looking at about 12 years, compliant through 15-16 through the end of the RPS, which is compliant here, 25 and 26. And showing the incremental amount of new wind that we'll need, and then totaling that to get the reductions that we find on the next page, which is really the key point that I want to make today. And, I'm a social scientist so my arithmetic is wrong; that should be 42 1/2 percent, not 48 percent, so I apologize for that. But the point being that you already have a program in place in the RPS. If we make it function effectively and cost effectively they can get a lot of the reductions that
EPA is asking for under the Clean Power Program.

So I think that should be heartening;

I wasn't here for the first session, but I understand there were -- some people presented that there may have been challenges with some of the first two building blocks; but here I think we already have a robust policy in place to make Building Block 3 work very well for Illinois.

So again, just to give you some of the natural picture, and to some extent this applies more regulated markets, but AWEA looked at the tradeoff between wind and gas and the savings that you from wind based on the price of natural gas. So obviously, as you would expect, as the natural gas becomes more expensive wind becomes a more effective driver and more cost-effective and more savings by including wind in the Clean Power Plan.

My last slide is just my policy recommendations. We talked about some of these, I think; that we should be using distribution charge as the main compliance function for RPS. I would look to convert the ACP to a real procurement obligation,
and then, I think in line with what the other folks have talked about, from a procurement standpoint we would like to see a portfolio approach. We would like to see a shifting away from complete reliance on one-year RECs to a combination of bundled long-term contracts for energy and RECs, followed by possibly other shorter-term REC-only contracts.

I would just note in closing that how to build new generation and incentivize of our new generation is a challenge on all the restructured markets and not just for renewables. We've seen that for conventional generation in Maryland and New Jersey cases. So all the restructured markets have wrestled with it and they've done it in different ways. But we have never said we should be 100 percent long-term bundled contracts. We've always thought that this portfolio approach is what makes the most sense. And the challenge has been we've kind of gained 100 percent too much short-term and we're just saying let's mix this up.

So I think that if we can fix the RPS in a sustainable funding stream, this can be a really
important and cost-effective building block for Illinois' compliance efforts towards 111(d). So thanks very much for the time and I'm happy to answer questions.

CHAIRMAN SCOTT: Thank you.

Commissioner Colgan?

COMMISSIONER COLGAN: You talked about Senate Bill 103 and you think the solution to this is to put this into the distribution charge. And, like most things in this business, rate making is a complicated process, and I have a real concern about moving more -- everybody wants to move more cost -- more of the cost recovery to the distribution charge.

There are some people -- there are some ratepayers in that distribution charge who aren't getting the benefits that they're actually paying for. And, so, have you given any thought of coming in in terms of proposing some sort of changes in the rate structure and the different classes of customers and how you would recover those costs through the distribution charge?

MR. ERIC THUMMA: Well, we're certainly open to
ideas and we're open to ideas that are separate than using the distribution charge. We've talked about that.

COMMISSIONER COLGAN: Well, we're open to ideas, too and to be able to actually do those sorts of things there has to be record of evidence about how that can be done.

MR. ERIC THUMMA: I think what we liked about the distribution charge, frankly, and maybe we have a different view on this and I need to understand your view better, is we actually thought that it was maybe the most transparent way to show folks what this is costing because it's a line item on the bill. This is how much renewables are costing whereas now it's sort of buried in either a generation charge for the competitive supplier or it's part of the IPA.

COMMISSIONER COLGAN: I'm not saying that the distribution charge is not a good idea, I am not saying that. But I am saying that it's not a simple idea.

MR. ERIC THUMMA: Okay.

COMMISSIONER COLGAN: It's a very complicated
idea to say that, Well, let's just put it in the distribution charge.

Well, does that mean everybody, all the customers? It's like -- well, let's raise taxes so we can pay for the societal costs that are huge and apparently are over-the-top. But, who pays the tax? Who's going to pay those taxes? And it's about the distribution charge -- I'm just sharing my thinking on this -- about how do you better structure different rate classes and rate structures so that, you know, people who aren't benefitting so much from the program or can't afford any more fixed costs, How do they benefit from it? So that's --

MR. ERIC THUMMA: We'll certainly take it under advisement. I appreciate that point.

CHAIRMAN SCOTT: Let me just ask you one question and I'll let you go. One of the existing wind -- all of this kind of contemplates building on the existing wind that we already have, and when I say "we," nationally, not just here in Illinois.

MR. ERIC THUMMA: Right.

CHAIRMAN SCOTT: Is there an issue with the age
and technology involved with some of the existing wind farms and is there additional cost there -- we're always talking about it in terms of building new; but there is an asset that's already out there. Is there an issue with that in terms of ongoing O&M?

MR. ERIC THUMMA: Yes. So there is ongoing operation and maintenance that tends to be a much smaller portion of our cost than capital cost, which is why when you talk to wind developers you probably hear us always talking about long-term contracts, long-term contracts because that's -- the primary challenge is financing that capital cost and getting -- sort of addressing the risk with that.

But there is ongoing operation and maintenance and we're learning more about that, right, because frankly, most wind farms in the country are younger. They're not the old latticework wind farms you saw in Altamont that were the original wind farms back long before I was in this business.

But the farms are meant to operate for 20 to 25 years. We obviously prefer to try to
amortize those over that twenty-year period, and that's the expectation of the industry. And, generally, the expectation of the warranties that companies engage in with the manufacturers.

CHAIRMAN SCOTT: Since we're looking at something that's going out an additional 20 -- 25 plus years, would the expectations be that the existing farms get new facilities on them? Is that --

MR. ERIC THUMMA: Yeah, I think that in most cases --

CHAIRMAN SCOTT: I'm worried about stranded cost here --

MR. ERIC THUMMA: Right. Sure. And I think you're raising an important question and maybe we haven't thought a lot about -- while we sort of scramble to get the initial investments in, and so we should think about that.

I would say that most wind farms of which I'm aware have options on their leases. So I think there's an expectation that those wind farms would be re-upped; re-powered if you will, after the 20-year period. You know, what I say today, that the
expectation would be we'd be closer to whatever the
market price of energy would be 20 years from now. I
probably won't be here to have to face the
consequences of that, but I think that would be the
expectation. That we're sort of -- we're taking
these positions and we're expecting them to be
re-powered and to be assets that would last longer
than 20 years and that in that in the future they
will be closer to market if not beating the market.
But we can't predict that far, of course; right?

CHAIRMAN SCOTT: We'll have to be back in 2034.
MR. ERIC THUMMA: Sure, I'll be here.
CHAIRMAN SCOTT: Thank you very much and thank
you to all of our panelists.
We'll take 15 and if the last panel
could, near the end of that break period, move up and
take seats, that will help us save a little time,
thanks.

(After a short break, the
policy session resumed as
follows:)
CHAIRMAN SCOTT: All right. Thanks very much
for getting back, and we're sort of on time. This is good.

Our last panel, as I mentioned earlier, we're going to do a little bit differently. We've got seven different entities that are going to start with a brief statement, no more than 5 minutes, and just kind of talking about energy efficiency. And then we've got a series of questions that we're going to get into as kind of a discussion -- group discussion then.

We'll introduce everybody at the beginning and then just go ahead and go in the order that we've listed here. Annette Beitel is the Independent Facilitator of the Illinois Energy Efficiency Stakeholder Advisory Group; John Cuttica is the Director of Energy Resources Center at UIC; Val Jensen, the Senior Vice President, Customer Operations from ComEd; Keith Martin, Director of Energy Efficiency and Craig Nelson, Vice President of Regulatory Affairs and Financial Services, from Ameren; Mel Nickerson, Deputy Director, Office of Energy & Recycling, Department of Commerce and
Economic Opportunity; James Potach, Senior Vice President, Energy and Sustainability Services from Schneider Electric; and Becky Stanfield, Deputy Director for Policy, Midwest Program of NRDC. That was in alphabetical order so there's obviously no agenda there.

Let's start with Annette, and if you would, just lead us on.

PRESENTATION

BY

MS. ANNETTE BEITEL

Sure. Thank you.

So Commissioners, thank you very much for inviting me to speak on this very important panel. I'm going to say a few words about the state of efficiency in Illinois. Specifically, I think that energy efficiency in Illinois compared to other jurisdictions is going extremely well.

I'd like to just mention a couple of areas where I think that Illinois really is a leader. Number one, I think as everybody knows, Illinois is in the top ten states in the ACEEE benchmarking
study, the only Midwestern state. Second, Illinois is really new on the block; it's one of the newer jurisdictions in the midwest to have an EEPS portfolio. And, despite that, Illinois has rocketed to the top very quickly in only five or six years.

Number 3, in benchmarking the Illinois programs and the portfolio administration against other leading jurisdictions, Illinois is being extremely cost efficient. So the admin cost for Ameren and ComEd, for example, are under 5 percent. Five percent is really considered to be the gold standard in low administration costs.

Number 2, Illinois is really running very market-driven programs. So instead of having utility representatives go out and market programs and drive up costs, the Illinois portfolios and program administrators have done an excellent job training the trade allies, training the vendors to go out and be the sales force for energy efficiency, really leading to market transformation.

Third, Illinois has a separation between administration and implementation. In a
number of jurisdictions, utilities try to do both and only bid out a piece of implementation, and then their implementation portfolio that they administer is never subject to the market. And so, the Illinois portfolio administrators decided we really want these most cost-competitive portfolios and they bid on a regular basis. Providers that are doing a really good job have stayed with the programs for a long time. Providers that are not doing so well wind up turning over; but all of the providers are subject to the market competition and so their costs are very low.

I recently was talking to one of the staff at the utilities and said, Why is it that you are doing such a great job in being so cost efficient compared to a lot of other utilities? And I loved the response, and I think really indicates why collectively Illinois is doing such a great job. The response was that his leadership, and specifically, in this case it was Val Jensen, does not see the ratepayer as utility ratepayer. He said, We are told all the time that we are the stewards; it is not our
money and we need to do the best for the ratepayers and the State of Illinois. And I thought that was very telling; I thought it really represented the right attitude towards efficiency and that really helps explain why Illinois is doing so well.

Some other indicia of how well Illinois is doing is that the electric utilities year after year have exceeded goal for under budget. And finally, even though there are five different portfolio administrators in Illinois, there's a very, very high degree of coordination. There's coordination north/south, there's coordination gas/electric, there's coordination between the states and the state programs and the utility programs, really in an almost unprecedented way, compared to what I've seen in other parts of the country. That's something to be very proud of.

When I was putting this presentation together I was trying to reflect on my experience here versus other places and trying to understand why is it Illinois is doing so well. And in my mind it really boils down to leadership. And I'm going to
name several names because I think that it's important to really recognize the many strong individuals in this state who've really contributed to the excellence, So: Chairman Scott; Val Jensen; Keith Martin; the stakeholders Rob Kelter, Karen Lusson and her technical advisor, Phil Mosenthal; Becky Stanfield and her technical advisor, Chris Neme; and ICC staff has also done a great job of really understanding the issues, working extremely hard, and really trying to defend the interest of the ratepayers.

So I just think there is a very broad and deep set of leaders in this state, working together to accomplish these goals. I think that the some of the key attributes of the leadership I'm seeing in Illinois, again in contrast to other jurisdictions is that a lot of the discussions are really fact-based, they're not rhetoric. People don't sit in their institutional positions, dig in their heels, and refuse to listen to other sides, which is very impressive.

The other thing that I've found is
that the utilities, even when they're not being
served to Iroquois and its CEO have been extremely
willing to share information that stakeholders have
asked for, to help the stakeholders really, again,
analyze in a fact-based way; that it's not under any
kind of compelling order, it's just that they're
willing to share because they want everybody to be
informed.

The discussions that I've seen have
been very respectful. People are willing to change
positions in discussion and then there is, again,
many beyond the leaders that I mentioned. Many smart
thoughtful people from around the country:
Massachusetts, Colorado, Vermont, who regularly
participate in discussions in Illinois and really
have elevated the quality of work and the results
here.

There are couple areas where I think
there is we can do better as a state. One is I think
we need to do a better job serving low- and
moderate-income customers, meaning those who are not
just poverty and eligible for WAP programs; but those
that are 80 percent and below the A-Atlantic area median income. And there's been analysis done in Illinois looking at the census tracts that are using the incentive programs and they're very highly correlated with income.

So we really have seen that the census tracts that have lower income, but not even super-low income, really are not using to the extent that others are, the standard incentive programs. So I worry about, essentially a progressive tax. And there are other programs I think we can look at to try and, you know, help do better in that area in Illinois -- and not the DCEO but everybody, you know, the utilities as well.

So another area of improvement is if we're seeking greater goals and really seeking to meet the 111(d) requirements with a big chunk of efficiency, I think we need to look at aligning the financial incentives of the program administers with higher efficiency. I think at some point it's not going to be realistic to expect greater performance when the entities are losing money and there's also
precedent of nonprofit administrators having some performance incentives and I do think if the goals are going to be increasingly high, that needs to be an area that's addressed.

CHAIRMAN SCOTT: Thank you, to wrap up --

MS. ANNETTE BEITEL: Oh, I'm sorry.

CHAIRMAN SCOTT: There's a couple things we're going to get into -- are the things we are going to get into during the sessions.

MS. ANNETTE BEITEL: Okay. Sure.

My final thought is, again, I think Illinois is doing a great job. You should all try to do better job of championing the results that Illinois has and working together to get greater results.

So thank you, very much.

CHAIRMAN SCOTT: Thank you. I appreciate it.

Mr. Cuttica.

PRESENTATION

BY

MR. JOHN CUTTICA

Yes, first I'd like to thank the
Chairman and the Commissioners and the commission staff for inviting me to participate on the panel. I submitted some written comments for you to review and would like to just quickly summarize some of the highlights there.

I'm not here to comment on the appropriateness of the proposed rule nor provide my opinion on the merits or the non-merits of it, but what I want to concentrate my remarks on combined heat and power and waste heat to power. And I will say that should the rule become law and State of Illinois be required to develop a compliance implementation plan, it is my opinion that CHP and waste heat to power should be seriously considered as a very viable and strong compliance option.

Although EPA did not explicitly consider CHP and waste heat to power when developing the four building blocks and determining the state and emission targets, EPA has already recognized the value of CHP and I'd like to read an excerpt from the proposed rule: "In all types of market structures, large energy users might independently see additional
energy efficiency opportunities or opportunities for self-generation using options such as combined heat and power..." and the excerpt goes on to say, "and in states can structure their plans to allow the CO2 reductions achieved at affected EGUs through such actions to assist in reaching compliance."

I'd also like to point out that CHP and waste heat to power can be utilized not only as a building block for technology, which we will discussing in this panel, but can also be utilized to reduce emission at the affected facilities themselves, which would be Building Block 1, or by substituting generation at EGUs with expanded use of renewable CHP or waste heat to power by other unaffected sources in the region, which, of course was the Building Block 3 that we just heard.

Just so that we're all on the same level playing field, let me very briefly define what we're talking about here. So CHP is an efficient and clean approach to generating electric power and useful thermal energy on-site at the point of use from a single fuel source. And waste heat to power,
which is a form of combined heat and power, captures waste heat that would typically be vented from an industrial facility and uses the heat to generate electricity with no additional fuel, no additional combustion and no incremental emissions.

So my handout provides four distinct reasons why CHP and waste heat to power should qualify as a best system of emission reduction or a BSER under the 111(d) proposed rule. And let me just quickly state them with a sentence or two on each one. You got more information on the handout in front of you.

CHP and waste heat to power reduces CO2 emissions and CHP can produce roughly about one-half the carbon emissions produce when generating the electricity and the heat separately as is done conventionally, so electricity from the grid and thermal energy from an on-site boiler. And the graphic shows that for a 5 megawatt gas turbine system the CO2 emissions from CHP is roughly about 23,000 tons versus the 45,000 tons from the conventional.
Number two, CHP and waste heat to power are cost-effective. You can take a look at that graphic, and in some detail later you can look at it in more detail, but it compares a 10 megawatt gas turbine CHP system with an equivalent capacity for a voltaic system, a 10 megawatt wind system and ten megawatt portion of a natural gas combined cycled plant. The rest of the assumptions you can see on the bottom of the graphic.

The bottom line of the graphic is that the CHP system compares very favorably with the competitors, and I'll also point out that today CHP systems do account for about 8 percent of the generated capacity in the US.

Number 3, CHP and waste heat to power enhance electrical liability. They do this by alleviating the stress and burden placed on overcrowded transmission and distribution lines. And I did point out an excerpt from the proposed rule that acknowledges this fact. We also know that CHP systems, when properly configured, have proven themselves during such tragedies as the Super Storm
Sandy, Hurricane Katrina, and the large blackout in
the Northeast about ten years ago when the CHP
systems on many of these installations were able to
keep the lights on during these prolonged grid
outages.

Finally, CHP and waste heat to power
are proven technologies. And I guess this is the
main point. Illinois is in a unique position in my
mind -- is in a unique position to capitalize on CHP
and waste heat to power while developing their
compliance plan. And why? Because there is
approximately 1.2 gigawatts of CHP installed in
Illinois today and operating. There exists a large
technical market potential for CHP in Illinois;
Illinois already recognizes CHP and waste heat to
power thanks to the ICC and the last plan
submissions, so it's already recognized these two
technologies in its state Energy Efficiency Portfolio
Standard Program. And Illinois also recognizes CHP
and the role it can play in its state energy
insurance plan.

So I'll conclude my remarks by
thanking the Commission for recognizing CHP and waste heat to power in this important workshop and panel discussion. There will be many choices and opportunities as you move closer to developing the compliance strategy. And again, I will state that I believe that CHP and waste heat to power can and should play a significant role in the process.

So, thank you.

CHAIRMAN SCOTT: Thank you, Mr. Cuttica.

Mr. Jensen?

PRESENTATION

BY

MR. VAL JENSEN

Thank you Mr. Chairman and Commissioners. I appreciate the opportunity to participate in the first of what I'm guessing is going to be a long series of steps toward a final and effective solution for Illinois and I want you know that we're committed to working with the Commission and other parties to make sure we get to that right solution.

I had a rather long set of prepared
remarks and I'm going to kind cut to the chase with some of it and try to give you a flavor of some of the challenge that we think we're going to face in trying to fit energy efficiency into an effective climate protection strategy. I would like to say, echoing something that Annette brought up early on, I think we have an extreme advantage, if I can characterize it as such, in Illinois. In the process that we put together we've had great cooperation from staff, from the Commission, and from other parties, which has made this a much more functional energy efficiency planning and implementation process than I think you're going to find pretty much anywhere in the country. I've worked prior to this job as a consultant in this field and I didn't think it could be done but I think it's fair to say, parties here would agree, that we built something pretty special and I think it's a great foundation for moving ahead. So a couple of things about energy efficiency and at least the framework that we understand from EPA to date. They envision or have made an assumption that energy efficiency could
supply about 1.5 percent of a reduction in energy use or electricity use per year, adding up to something like 12 percent cumulatively by 2029. In Illinois, at least speaking for ComEd, we are currently at about 1.5 percent annual incremental reduction in electricity deliveries.

So just comparing where we are today with what might be recovered -- might be expected under EPA's strategy, you'd think we've kind of gotten it manned. The problem is there's a long time between today and 2029 and a lot can change. So there are a couple of things I'd like to bring to your attention.

One of which is that in 2020 federal statute brings into effect a new lighting standard, which will raise significantly the required efficiency for residential lighting. Now, because of the way we measure energy efficiency savings in this business, the enactment of additional efficiency standards essentially takes away savings that utility programs would otherwise be able to acquire. So in 2020 we will go from roughly 1400 gigawatt hours a
year in savings to 1200 just by virtue of the federal standards going up.

Now, we think that can be replaced. We think there's certainly additional potential out there; but looking at the cost curve for acquiring energy efficiency from where we sit today, we're starting to look at that kind of traditional hockey stick where incremental energy efficiency savings look to us today to be much more expensive than what we've had in the past. Incrementally it costs us about 20 cents on the first year basis to save a kilowatt hour. That marginal cost is going to double, we think by the time we get near the end of this decade and we're trying to replace those cheap lighting savings.

So one of the challenges is even though we think there's a lot of potential left to recover, we think the cost, at least looking at it today, is going to be substantially higher than it is right now.

Looking at a recent potential study that was done for us under the state law that we
operate under, we're operating at about -- we expect
to operate at about 70 percent of what the consultant
identified as maximum achievable potential over the
next five years. We think we can reach what is
maximum achievable potential, but the cost that
they've identified would be roughly twice what we're
spending now. So we're spending roughly $200 million
dollars today. Next year, we will be investing $250
million dollars of customer money, and to get to that
next level of efficiency potential we're estimating
it could cost as much as $500 million a year.

As you know, there are two pieces to
Illinois' energy efficiency framework. There is the
original piece enacted in 2007 and then there's the
piece administered by the IPA that was enacted in
2011. Under the original piece we are capped at 2
percent of revenue. Basically customer bills are not
to rise more than 2 percent to fund energy
efficiency. Under the IPA process there is no such
cap on customer billing impact. So to reach this
maximum achievable potential, we would have to shift
a lot of funding into this IPA process. And we would
go from what we estimate right now to be roughly at 2 percent bill impact to closely a 6 percent bill impact for certain customers.

Now the way the Commission actually balances between this original process of and the IPA process makes a big difference in terms of who bears those costs. But, right now, under the IPA process, those dollars can only fund energy efficiency for residential and small business customers.

So, given our current structure in Illinois, a larger burden relatively could be falling on residential/small business customers as we try and meet that potential.

So that said, let me raise a couple of issues that we think will be important for parties to address over the next couple of years as we wrote this out. First, while there's been a lot of talk about a rate-based method for complying with 111(d), we think energy efficiency can do equally well under mass-based or rate-based. In fact, there may be some reason to believe under a mass-based standard we could be more creative with how we
develop energy efficiency.

Second, a really, really important piece of how energy efficiency works under any kind of climate regime is the evaluation framework. And I think we're lucky in Illinois that we have probably one of the strongest evaluation systems going across the country. That system was not built without a lot of pain on all sides, and by me calling it good means I really don't like it. It puts a lot of pressure on the utilities and we've lost a lot of savings that we thought we actually acquired by virtue of the evaluation process.

That said, I think it's fair, it counts as well as we can count. But, I think if you look at the evaluation debate around the country you're going to see people start to be asking some questions about whether the way we have done energy efficiency evaluations historically is the right way to do it in the future.

I don't know the answer to that but I think this process gives us an opportunity to ask those questions in a context of our Illinois process
and just make sure we're all still aligned on what
the right way to count energy savings would be.

The final thing I guess I'd like to
raise -- and I've already hinted at it, is this
dichotomy of bifurcated energy efficiency process in
Illinois. There were lots of good reasons for why it
was done this way, but the end result is a process
that I don't think any of us are all that thrilled
with. It forces us to deal with two sets of
statutory terminology two sets of standards; two sets
of cost recovery mechanisms to some extent; two
different approval processes, and it makes it
difficult for us to effectively sync up an energy
efficiency portfolio. I know I've also causes issues
with DCEO because it's unclear if they were allowed
to participate, not allowed to participate, in this
new IPA process.

These are both statutory processes and
I'm not sure the extent to which we can do much about
that. We'll make the best of whatever the situation
is, but to the extent that we can have a discussion
about how we might be able to harmonize those two
processes, I think we'll be in a much better position
to achieve all that we can with energy efficiency
under 111(d).

Thank you.

CHAIRMAN SCOTT: Thank you, Mr. Jensen.

Mr. Martin? Mr. Nelson?

MR. CRAIG NELSON: I'll make our comments and
I'd appreciate if you direct touch questions to
Keith.

CHAIRMAN SCOTT: Fair enough.

PRESENTATION
BY
MR. CRAIG NELSON

Let me start -- thank you for this
opportunity to express our opinion. Let me start
with Ameren's overall view on the Clean Power Plan.
I'll be very brief on that. But Ameren supports
environmentally sustainable operations. However, we
think that the current draft of the plan is
unworkable and not legal. Despite that comment,
though, let me address modifications that we think
would make it -- constructive comments to make it
workable, both to the modifications to the rule and changes in Illinois law that we think we need.

So modifications to the rule, the 2020 target's very tough. And we think there should be some flexibility around the status to what day to achieve that.

In addition, the 2030 Rule is a tough one and some orderly retirement of coal plants could significantly reduce costs. So our sister utilities analyzed the 2020 date and the 2030 date and Ameren Missouri has a plan to achieve the level of savings in the Clean Power Plan by 2035 at a cost of $4 billion less. So some flexibility can significantly reduce the cost.

Moving now to energy efficiency. We think that the draft rule should be modified to preserve the State of Illinois' control over energy efficiency. We think that's very important and of course we'd like credit for EE expenditures since 2012 and those modifications.

So, focusing on energy efficiency, let me go through two scenarios very briefly. The first
scenario is let's suppose that EPA cannot go beyond the fence -- and what I mean by that is they cannot impose Block 4 on the states or delivery service companies like Ameren Illinois. Under this scenario we think it would make sense to have a legislative framework that would allow Ameren Illinois to spend more on energy efficiency and sell credits to the generators so they can comply with the law. And, of course, we'd use that money then to offset costs that would be recoverable from our customers. So that's a way to -- if they can't go beyond the fence, to participate and be constructive under that scenario. We think we need the law change because Illinois law doesn't contemplate us spending more and selling credits to generators. So that's one law change.

Under scenario 2, where the courts decide that EPA can go beyond the fence, we think that there are changes in law needed in Illinois to mesh this up, to sync it up -- however you want to say it. So in the original EE Law, there are state statutory caps, there's a 3-year planning period that may not coincide with the planning period the EPA has
in mind, and then there are important portfolio objectives. And we've mentioned already the Illinois objective under state law of making sure that low-income and medium-income customers get their fair share of the direct benefits of EE, and we want to make sure that happens under this EPA rule as well. So there could be a -- there should be a clarification of that.

And, under the IPA EE Law, the second law, Val talked about -- the law does not allow the additional funding for larger customers -- in our case over 150 KW, that's a fix that needs to be made. In my opinion, it's not clear under Illinois law that IPA EE Law can be scratched to accomplish everything that the EPA rule wants. I'm talking about permissible costs, permissible measures, permissible benefits. There needs to be some clarification in Illinois law to accomplish that, I think.

Then, the goals and responsibilities -- as long as we're fixing the law, the goals and responsibilities between the Illinois Power Agency and the utilities under the IPA EE Law
would be helpful, too.

So those are fixes and then consumer and utility protections needed. In our case, we think that energy expenditures make up about 6 percent of the residential bill right now. And so we're talking about spending more money on energy efficiency a very good purpose. So one law change that we would suggest in Illinois is some rate impact protection for customers, some maximum amount of spend or some maximum rate impact. Along with that, a great impact mitigation is needed, so as increase EE spending, rather than charge it all to customers in the year of the spend -- some of these measures have long lives, 5, 10, 20 years possibly. And we would suggest that amortizing those costs over the life of the measure makes sense, and then, from the utility perspective, the unamortized balance would go in rate-based and we'd earn a return at our costs of capital.

So those are two protections for consumers, a cap on the rate impact and rate mitigation, spreading the cost over time, and then a
protection for the utility; there is revenue erosion and some legislation -- some legislative solution like a decoupling rider we think would be in order. So those are the protections that we think would be helpful for the consumer of the utility and with that will conclude our comments.

CHAIRMAN SCOTT: Thank you, Mr. Nelson.

Mr. Nickerson?

MR. MEL NICKERSON: Oh, okay. I thought I was going last so --

CHAIRMAN SCOTT: It's alphabetically, straight alphabetical.

MR. MEL NICKERSON: All right. Well, again, Chairman Scott and Commissioners, thank you for the opportunity to be here this afternoon. Just a brief matter of housekeeping, there's a small typo I noted, it has me listed as Mel Nickerson. My name is Melville Nickerson. It took me 38 years to grow into my name so I wear it as a badge.

CHAIRMAN SCOTT: Melville.
PRESENTATION

BY

MR. MEL NICKERSON

All right. Thank you. One final matter of housekeeping, in my short tenure at Department of Commerce and Economic Opportunity as Deputy Director of the State's Energy and Recycling Office, I've had the good fortune to learn many things. My wife has been an absolutely fantastic partner and mentor and teacher, if you will. I recount an occurrence, an event, last fall when I was speaking at my church. I finished up and exited the platform and we got into the car and I put my key into the ignition. Before I turned the ignition on my wife said, Do you like to hear the sound of your own voice? And I thought to myself, Well, yes, I do. But I learned something very important, brevity is always a good thing.

So I'm going give you just a very quick overview of the programs that we won, the Department of Commerce of Economic Opportunity. I'll make a couple of points and then I'll reserve some
other comments for the various questions that have been put forward.

First and foremost, the Department of Commerce and Economic Opportunity is supportive of the Clean Power Plan. No pun intended but we see it as a great economic opportunity. Certainly the infrastructure that will be invested in Illinois as a result of the plan is good for our state's economy, not only in terms of revenue streams but also in terms of job creation; it's a very vibrant opportunity for our state.

That being said, we also are very aware that climate change is not tree-hugger concept, forgive the expression for those I may have offended.

Just this past Sunday, 166 nations across the world, various protest marches took place around climate change. We all felt the effects of climate change just this past winter, as the Pacific -- waters in the Pacific warmed and it shifted the flow of the polar air mass down into lovely Chicago. So we all know this is a renewable fact and we have some great opportunities here to grapple with these issues and
move forward.

Turning attention now to the programs that we offer to the residents of the State of Illinois. We run energy efficient program under the Energy Efficiency Portfolio Plan. We serve -- I will say with a great deal of pride, two of the toughest sectors of our state to serve, which are low-income residential folks because there is a lack of resource there to take advantage of programs and incentives and we find it cost-effective or a prudent approach to move forward outside the cost cap because it is very hard to serve the sector of our state.

In addition, municipalities, local governments, as we all know are still reeling from the downturn in the economy that took place back in 2007, 2008, 2009. So we find it important in some instances to again, offer higher incentives to help these desperate constituents be able to implement cost -- or energy efficient measures.

I have a couple of numbers for you, for folks that like numbers. Energy efficiency -- our energy efficiency programs have yielded -- excuse
me, over 529,000 megawatts of savings. Since we've implemented them back in 2008. That is the equivalent of over 139,000 metric tons of CO2 to be displaced.

Those sound like big numbers but the sobering reality is that represents less than 2 percent of the 2020 goal as was presented this past August by the Illinois EPA, based on Jim Ross's PowerPoint presentation. It is clear that for energy efficiency to play a significant role in compliance with the 111(d) rule, we will need to increase the amount of energy efficiency that the state currently -- has in today's -- well, in today's present time.

In addition, I also wanted to highlight another program that is sort of off-the-grid or off-the-books, at least in terms of the Illinois Commerce Commission. We also have a fund called the Residential Energy Efficiency Trust Fund. It is generated through a small charge on delivery service of both electricity and gas. That program amounts to about $3 to $4 million annually.
And it is very important because it allows us to serve non-utility territories such as Springfield, generating their own power through electricity, not having a very robust opportunity to serve the residents through both electric and gas -- well, electric savings.

In addition, we also collaborate with sister offices within our department such as the Energy Assurance Office, which runs the LIHEAP program. We also collaborate with the Urban Weatherization program as well as entities outside of our agency such as Illinois Housing Development Authority.

I want to make one plug for Building Block 3. We also run a small but very effective renewable energy program, and not to poke my colleague, Anthony Star, but I like to say that is the only program that guarantees solar on the rooftops in the State of Illinois. It's a grant-based program; it, again, is generated from a small charge on delivery service to all residential electric customers as well as commercial and
industrial in the State of Illinois generates
annually approximately $5 to $7 million. And we're
able to do fantastic things since the inception of
the program in 1999 such as generating 158 megawatts
of renewable energy and that would displace
approximately 261,000 metric tons of CO2.

The total the program has invested is
$56 million. There have been over 2,000 grants that
have been issued, and we've been able to leverage
with that money $375 million in pet projects, that's
a 6:1 investment ratio. We've been able to do
fantastic things like put solar on -- partner to put
solar on Illinois Tollway's rooftops, of their main
facility, as well as partnering with the Shedd
Aquarium on their ambitious plan to reduce their
energy consumption by 15 percent by the year 2017.

All that being said, that represents
less than 1 percent of the over 9 million megawatts
that will be needed by the -- according to the
Illinois EPA model that my colleague, Jim Ross,
presented back in August.

I simply am trying to draw just
attention to the fact that we will need to do more, and in the process of doing more we will need to grapple with other issues such as EMV, evaluation of all our energy efficiency program. Currently, we use a net-to-gross approach, but certainly I think that would be a hamstrung in Illinois. Should we use that same method to comply with the 111(d) rule since there is a maximum amount of energy efficiency that is being seen, we should use that number to draw our energy efficiency compliance.

In addition, there is another issue that we should take note of. Right now, according to the statute, according to the law, we look at energy efficiency on an annual basis in terms of how both our office, DCEO, as well as the utilities are complying with their electric and gas savings goals. If we do that, we are going to be missing a great opportunity to maximize the reality of these energy efficiency savings.

I'll give you one example. We partner -- we're very proud to partner with Kate Brown of the University of Illinois. There's a
specific focus on Public Housing Authority. In this
country we spend over $7 billion of taxpayer money on
Public Housing Authority energy bills -- utility
bills. We invested $4.1 million just this past year
that yielded 6.3 -- excuse me 60.3 million
kilowatts -- I apologize. We yielded -- yes, $6.3
million kilowatts of energy saved within a five-year
period, and that would grow exponentially to be 31
million kilowatt hours of energy savings. So I'm
just trying to underscore and draw emphasis to the
fact that we will need to grapple with the issue of
how long we will count the savings; should it be for
the useful life of the savings or should it be some
agreed upon, negotiated intermediate solution.

That being said, thank you, very much.

I hope I was brief.

CHAIRMAN SCOTT: Thank you. Well, I'll have to
report back to your wife. I apologized if I
mispronounced your name.

MR. JAMES POTACH: Thank you, Chairman Scott.

James Potach for Schneider Electric --

CHAIRMAN SCOTT: I think you need to use your
mic, too.

MR. JAMES POTACH: Good? Okay.

PRESENTATION

BY

MR. JAMES POTACH

James Potach for Schneider Electric

representing a group of energy services companies

referred to as ESCOs in the market. So I'm here to

represent us. We are the companies that provide the

technology and services typically to deliver energy

efficiency in the market today. Our companies, as a

rule -- we've got decades of experience in providing

these projects -- billions of dollars invested around

the research and development of the technology and

literally billions delivered in measured and verified

savings in the market.

We've got a couple hundred thousand

people amongst our companies in the US alone 380

manufacturing plants and we serve a very broad set of

markets, buildings like the one we're in here;

universities; hospitals; data centers; office

buildings; manufacturing facilities; water treatment
plants. The reason I share all that with you is at the end of the day we believe we can bring practical experience to energy efficiency measures as it relates to 111(d). And we know there's a cost-effective method to deliver the savings and the corresponding CO2 savings as well by focusing on third-party energy efficiency projects as part of this rule, leveraging what we call the Energy Savings Performance Contract, it's a very established method of contracting that's been around for an excess of 30 years in the market.

Three points I'd like you to consider about that. One is that we can deliver these project, all of our companies, we can deliver them at scale. Currently it's about a $5 billion market annually in the United States. So each year out of that $5 billion we're literally delivering an incremental $6 billion of energy savings across the United States year over year, over year. So we have the scale to deliver.

Secondly, the results are absolutely real. They are measured and they're verified. So we
all use a standard development that the Department of Energy -- it's internationally accepted, it's applied by certified professionals, and it verifies the actual results and it's largely accepted in the market.

The third point to consider is for energy efficiency measures, one of the market barriers is just capital, capital to do the projects -- the hockey stick effect in some ways. ESPC -- the beauty of ESPC is that it leverages the savings of energy efficiency and the corresponding savings off of utility bills to fund the project. And the project is originally funded by a third-party financier, banks to household names we all know of, that finance this market. So there's plenty of capital available in the market to fund energy efficiency measures.

Three other points I'd like you to consider and then I'll close. Why take advantage of third-party measures? Number 1 is it's absolutely proven. So in the market if you look at states that have adopted this model around energy savings
performance contract, there's a long history of performance, and the beauty of the contracting vehicle is companies like ourselves, we guarantee the results over a 10 to 20 years period, typically. So that means we can financially stand behind the results or we can make up the difference if we don't deliver. And none of us like to write a lot of checks. So it's sustained results over the long period and it's proven.

The second is the EPA guidelines, as I understand them, talk about a percent and a half of opportunity per year of savings around the assumption of that's based on the utility program. And, while those are good, the investment in ESPC performance contracts is literally almost the same amount as the utility programs. So if the states adopt these third-party measures even though they double the opportunity to deliver energy efficiency in the state.

The last point I'll make is that companies like ours are able to really deliver deep energy savings, meaning we have -- when we deal with
our clients they typically don't have the expertise
or -- beyond kind of a more basic energy efficiency
measures. And because we have a contractual
relationship over 10 or 20 years we're able to pay
for these deeper kind of mechanical or
infrastructural improvements that provide a whole
other layer of energy savings and for over a very
long period of time.

A couple of you asked questions about
jobs. We know that through research and studies that
great deal of the work that we do in our local area
is subcontracted with local labor and we know by the
dollar how many jobs were created and it does create
a lot of jobs in the local market where we work.

So as a group we've got the practical
experience. It's very pragmatic, it's proven in the
market. We developed for the EPA and for states kind
of a ten step pragmatic guide to problematic energy
efficiency program for end users. And we believe
that the states should urge the EPA to have specific
guidelines addressing this option around energy
efficiency -- third-party energy efficiency for

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CHAIRMAN SCOTT: Thank you very much.

And Ms. Stanfield.

PRESENTATION

BY

MS. BECKY STANFIELD

Thank you, Mr. Chairman and fellow panelists. My name is Becky Stanfield, I'm the Deputy Director for Policy of the National Resources Defense Counsel's Midwest Office, and it's great to be here today, talking about this subject and to be here with the people who over the last 6 or 7 years have actually built impressive regulatory infrastructure, an impressive industry in Illinois to provide energy efficiencies savings.

I'm from southern Illinois so I generally talk a little slower than everybody else. I appreciate that everyone has focused their attention for this long, and I'm going to try to step up the pace a little bit for this purpose.

Going back to Annette's theme, energy efficiency has a huge success story in Illinois.
U.S. EPA's projection that we can hit 1.5 percent per year by 2017 is extremely conservative; we are basically already there. We are reducing demand by 1.4 percent every year through energy efficiency and at the same time, we are doing it at well below the avoided cost. So I've provided a cost curve of ComEd's programs for everybody in this lovely teal-colored PowerPoint presentation. So if you take a look at that, what it shows is that the EEPS and the IPA programs are almost universally well under the avoided cost line -- the orange line, and they're very few number of programs that are above the line, represent programs that are about 0.1 percent of savings in the portfolio. So these are extremely cost-effective programs. And this is true, even though that line is much lower than it should be. So in Illinois we are undervaluing the benefit side of the equation substantially.

And NRDC commissioned a study with RAP that looked at what the price suppression effects are of the energy efficiency programs we're running in Illinois. So what are our programs doing to reduce
the regional price of power. That is not included in our avoided cost methodology in Illinois, and if it were, that orange line would be higher and a lot of programs that have hadn't seemed as cost-effective, of course would, and we'd be able to do a lot more on energy efficiency in Illinois than we're doing now.

The programs are serving all customer classes and they're doing a better and better job at doing so. So we're reaching the classic hard to reach customers in multifamily affordable housing in the large commercial buildings, and we are -- and those programs are becoming a bigger and bigger focus of the portfolio. As utility programs are able to enable non-utility programs such as Retrofit Chicago, which is addressing large commercial buildings, or elevates an energy saver's program, which is first-class nationally of how to reach multifamily affordable housing.

Our current portfolio is going to reduce carbon emissions by 12 million tons by 2022. So, we're delivering substantial carbon savings if we continue to do the same level of savings we're doing
now. If we ramp up to the cost-effective potential, that number could be increased to 19 million tons per year.

And, so -- and cost effectively -- again, so I wanted to underscore that if we do not do it with energy efficiency we will have to do it with something that is more expensive. So from the perspective of ratepayers, this is the part of your bill that pays you back, and limiting it to less than what's cost-effective is only increasing the cost that ratepayers end up paying.

The other point I want to make is that we're creating jobs with energy efficiency in Illinois. There are 96,000 existing clean energy jobs, 62 percent of which are in energy efficiency. And we estimate that if we were to do a RGGI-like approach to complying with 111(d) and invest, as RGGI does, 65 percent of the proceeds in energy efficiency, we could create another 14,000 direct jobs in the energy efficiency industry, and as many as 28,000 indirect energy efficiency jobs.

We do believe that we can do more than
we're doing now cost effectively. I don't deny that there are challenges to getting there, but I think it's doable and cheaper than getting the emission reductions in any other way. ComEd and DCEO both have potential studies that found that there's achievable potential above 2 percent of sales per year. So if we are able to save more than 2 percent of demand each per year -- and in fact, ComEd's residential programs are already achieving savings at a greater level than their maximum achievable potential said. So those studies are notoriously conservative in what they project the achievable potential is.

Other states are already achieving energy efficiency at more than 2 percent sales per year including Massachusetts, Nevada, Vermont and Arizona. And while folks pointed to the fact that their avoided costs are higher, they're achieving those levels at still very low levelized costs of energy savings. In Massachusetts it's 3.9 cents per kilowatt hour, so that's still well below Illinois' avoided costs.
There're lots of technologies and measures that aren't represented in our current portfolios or in potential studies, including CHP, as John was pointing out. LEDs in the commercial lighting have a lot of potential, heat pumps and building controls and other technologies that are actually enabled by this Smart Grid investment that we're making in Illinois.

We also get to count other energy efficiency policies beyond utility improvement policies so -- building codes for example can be measured and included as part of the compliance strategy, which underscores the need for EM&V that actually differentiates between what efficiency the utilities are delivering and what's being delivered by other policies.

There are policy barriers in existing law that others have already pointed out and have constrained budgets especially for industrial and large commercial projects. Joint delivery programs that depend substantially on gas savings are even more constrained by low gas efficiency budgets. For
some market segments where assets to capital is a
problem, we need better financing mechanisms to
combine with the utility incentive dollars to get the
projects done.

And better accounting for benefits
including the price effect that I talked about
before, so the effect of our programs on regional
power prices, and non-energy benefits particularly in
low-income housing would allow many programs to be
offered that are currently excluded from the
portfolios.

So why to prioritize efficiencies for
the purpose of 111(d)? Slide 15 in my deck shows
it's by far it's the least expensive resource on a
levelized-cost basis. So the more you capture, the
more you can manage your costs in the electric
system. Also it also means that we're investing in
buildings -- making people's homes healthier,
creating good jobs in our communities at the same
time.

Again, EPA -- sharply underestimated
the potential for savings. They estimated that we
could get to 11.6 percent reduction cumulatively. And we know that we could do well over 18 percent with the utility programs alone and can likely get to a 20 percent reduction with other policies. How to do it? I think, as someone else said, we can do it through a portfolio-approach or mass-approach, note that in both the RGGI and Northeast carbon regulatory system and in California what they've done is overlaid a mass-based approach on top of strong state energy policies. So I think that's basically what we need in Illinois. We can't move from what we have now to an entirely mass-based system but we can layer it on top of a strong set of energy policies in our state to very good effect.

CHAIRMAN SCOTT: Thank you.

Let me now spend the last 40 minutes that we've got talking about a couple areas and may combine them a little bit.

I think I want to start where Becky ended up and maybe go to the utility folks first and then to Annette and Mel, too -- or Melville -- I'm sorry -- and ask about what we're leaving on the
table. One of the big issues for us, always, and as we evaluate the programs from a Commission as they're brought to us, we've asked a lot of questions recently about the programs that are out there. What -- and Becky kind of hits that in terms of overall numbers first of all, ask if the others on the panel agree in terms of -- kind of the scope of how much more is out there in terms of energy efficiency. Then we can talk a little bit about how we get there, and maybe some things that are stopping us from getting there.

So with that, I don't know, if you wanted to start us off and then Keith --

MR. NELSON: I was going to say, Keith is itching to say something.

MR. KEITH MARTIN: No, no, no.

CHAIRMAN SCOTT: We got to ask the hard questions. So...

MR. CRAIG NELSON: I don't know that I would agree word for word with Becky, I think we politely disagree on some of the finer points. I do think there is additional potential out there; I think we
recognize that. We have, as she has noted, exceeded what the estimate for maximum potential is already. So that -- and it does call into question how valid some of those studies could be. And I think that the thing that I both worry about and gives me optimism is I think there's this whole new world of smart energy out there that allows us to combine investments for making in AMI Smart Meters with cutting edge technology in the home or business. And I think there's going to be a lot of potential out there that we don't know how to characterize yet.

So I don't think we're bumping up against the ceiling. What I don't know, Mr. Chairman, is what all of this is going to cost us, and that really is something we -- I guess we're labelled as being ultraconservative on this; but we do worry about the rate impacts on customers. There's a lot of activity going on in the Illinois market that is adding to customers' bills and we just have to be mindful of that. As good as this may be and as much as it may save certain people, other people will not take advantage of these efficiency
programs and yet they will pay for them.

Somewhere along the line we're going
to have to figure out what that looks like and what
the right balance is. So to conclude, yes, I think
substantially more potential, worried about the cost,
and think that we're going to find a lot out in the
next five years that we never would have imagined
five years ago.

MR. KEITH MARTIN: Yeah, I certainly agree with
those comments. I'll add a couple points.

First of all, I think we need to be a
little careful using the current portfolio
performance as an indicator of the future. As Val
points out, the programs are going to look
significantly different. The potential studies that
were used in the EPA analysis, seven of those did not
go beyond 2020. Only three of them did, and then
they only went just a few years into this to
2020/2030 period.

You know, we've all talked about how
lighting has been an important part of the portfolio,
but I think we need to understand that baseload or
the baseline for lighting is changing, and that is a significant change. And, as an illustration of that, if we put in a 60 -- or replace 60 watt equivalent incandescent with a CFL we save 46 watts. By 2020 that will be the baseline. The next level of technology is the LED and we save 4 watts. So lighting certainly is going to have a -- is going to look very different in the portfolio mix. Now, I agree with Val that there are a lot of behavioral-type programs that will have a very significant impact. I think there's a lot industrial potential that we still need to take a look at, which requires the legislative change.

The other thing, though, I wanted to mention that I think we need to be very aware of is that the carbon reductions are cumulative and really require long-lived measures. Today’s portfolio focuses on short-lived measures: Behavioral programs, lighting and so forth. So it’s -- again, it’s another way in which I think we need to transform the portfolio to really achieve those targets.
CHAIRMAN SCOTT: Appreciate those comments.

MS. STANFIELD: May I respond to some of those comments?

CHAIRMAN SCOTT: Sure.

MS. BECKY STANFIELD: So the reason I brought up Massachusetts before, is because they have now gone to a portfolio that's really designed to get deeper savings. And their portfolio has a longer measure life and still is coming in at 3.9 cents per kilowatt hour. So it doesn't necessarily follow that once you start to do the deeper portfolio measures that your cost is going to go above Illinois' avoided cost. So that's still well within what we would otherwise be spending on more expensive resources.

The other thing to Val's point on making sure --

COMMISSIONER COLGAN: Well, before you go on, what is it that Massachusetts is doing that we're not doing?

MS. BECKY STANFIELD: I think that they have a policy. You can see one my slides that as soon as they set a policy that they were going to capture 2
percent, that's when they got busy trying to figure out how to do it cost effectively. So it is not so much a technical or economic constraint, it's a policy constraint. We're not figuring out how to do it because our policy doesn't direct us to.

COMMISSIONER COLGAN: But the example was the lighting example: How you can save so much going from incandescent to CFL and then not so much when you go to the next steps. And I'm just kind of wondering what it is -- I don't mean to put you on the spot, I just thought that maybe there were examples of what they're doing.

MS. BECKY STANFIELD: One example you can see on slide 12 of my presentation, is looking at commercial lighting. So the difference between what you -- a typical measure today would be in a T8 fluorescent light fixture versus the LED design. Still an enormous amount of potential in lighting, and a lot of it is in commercial lighting. And our potential studies are not taking these kinds of measures into account at this point.

Also, just to reply to what Val said
about the costs, particularly for non participants.
We have done a preliminary analysis of ComEd's
programs to look at whether the non-energy avoided
cost, so the costs that are being avoided and saved
even for nonparticipants, is commiserate with what
people are paying, and it is. So even if you take
out the non -- or the energy benefits that are in the
avoided cost -- the average avoided costs, you're
still getting cost-effectiveness for even
nonparticipants.

COMMISSIONER COLGAN: Can you just give a
couple of examples of the non-energy avoided costs.

MS. BECKY STANFIELD: Yes. So capital costs,
avoided T & D, the price suppression effect.

MR. JOHN CUTTICA: Can I make a point?

CHAIRMAN SCOTT: Sure.

MR. JOHN CUTTICA: In Massachusetts -- I have
to put in a plug for CHP since that's why I am here.
In Massachusetts they do have a very aggressive
combined heat and power program that's included in
both their energy efficiency standard as well as -- I
think that they have an advanced energy portfolio
standard. I'm racking my brain and I'm too old, I can't remember the percentage; but it seems to me that it was a pretty large percentage of their energy savings actually came from the CHP program over the last several years. I wish I could remember the exact percentage. I think it's somewhere above 25 percent, but don't hold me to that. I got to check.

MS. ANNETTE BEITEL: I'll just say a few remarks on the cost issue as well as the potential that we're leaving on the table. So I don't think it's necessarily true that greater efficiency yields --

CHAIRMAN SCOTT: Could see if your mic is on?

MS. ANNETTE BEITEL: So I am not sure that over time that greater efficiency necessarily leads to greater cost per unit energy. And I just want to throw out an example of efficient refrigerators. So over the past 40 years, the energy usage of refrigerators has dropped by 75 percent, the cost has dropped by two-thirds and refrigerators are bigger. And, we also have seen dramatically how the costs of FCFLs and LEDs have dropped over time as they've
really had greater penetration in the market. So I just don't think that we really know whether cost is necessarily going to rise as much as they're forecasting because we don't know what's going to happen to price over time, and we have lots of examples of where prices really go down. The second piece is on the potential that we're leaving on the table. We don't know -- we don't have a crystal ball around emerging technologies and those are fairly critical with a lot of other efficiency opportunities. And they are not counted potential studies. Just by way of example, California spends -- they have a much bigger budget, they spend about a billion dollars per year on efficiency. They spend $19.3 million on emerging technologies and they identify a lot of future opportunities. At the other end of the spectrum, Wisconsin, which has a much smaller budget, $85 million, they have a state policy of trying to identify 20 to 25 new emerging technology products or services per year that can be brought into the state; and they've been successful.
And some of those new tech have really save a significant percent of energy.

COMMISSIONER COLGAN: That part of the statute is capped in that regard --

MS. ANNETTE BEITEL: I'm sorry?

COMMISSIONER COLGAN: Our statue is capped on emergency technologies; is that correct?

MS. ANNETTE BEITEL: That is correct.

COMMISSIONER COLGAN: Three percent?

MS. ANNETTE BEITEL: Three percent. And I think that's an issue to consider in the context of getting greater savings.

CHAIRMAN SCOTT: Let me ask you too because when I stopped you originally you were talking about low and moderate-income. And I want to ask about that and then go to Nickerson because that's the programs that the DCEO administered.

So you're saying that we need to do a better job in terms of providing benefits to low or moderate-income customers here.

How would we do that? How does that --
MS ANNETTE BEITEL: Okay. So very quickly,

number 1, I think it needs to be our responsibility,
not just at DCEO but also the utilities, and I think
there is statutory authority for that.

   Number 2, I think there is a

misconception that to serve low/mod-income customers
effectively, you need to pay 100 percent of the
measure cost or 100 percent of the incremental
measure cost. And there's some programs in other
jurisdictions, like Wisconsin, where the incentives
for low-income customers are higher, you know, maybe
by 50 percent compared to the regular customers. But
they still get high uptake, even though there is a
customer co-pay, because they're using very creative
ways, or effective ways I should say, of getting the
programs into low/mod-income customers by using
faith-based organizations, community-based
organizations and the studies have shown that using
standard marketing techniques for low/mod-income
customers are not effective.

   So those are just two examples.

CHAIRMAN SCOTT: Okay, thanks.
Mr. Nickerson, do you want to talk about where you think there's some -- with the programs that you operate, where there's some additional PE that we can find.

MR. MEL NICKERSON: Sure. Absolutely.

First, let me just briefly respond to the idea that I now just put forward, regarding low-income programs. I mean, I cannot necessarily comment on expanding programs, although we've had some discussions about that during the IPA docket last year. So those issues are somewhat well known but -- so they're more broadly understood. There is some question as to what role, if any, DCEO should play, according to statutory language. So I've prohibited our engagement as you would have envisioned us getting involved, in the IPA annual procurement of energy efficiency.

We somewhat -- I hope we're not talking past each other, but certainly based upon our experience over the last 7 years, we understand this is a hard sector of the utility market to serve, low income folks. They spend the majority of their
monthly income -- excuse me, they spend the highest
majority of their monthly income on their utility
bills, as compared to others in similar categories.
And so, what we find is when we have the opportunity
to enter into a residence, we want to maximize the
savings, as opposed to trying to duplicate a minimal
amount of savings over a wider footprint. It's very
hard, as I'm sure the utilities can verify, to gain
access to someone's home let alone their business,
even though albeit under great auspices.

What I do want to address very
quickly, though, is our public sector program in
terms of potential that's being left on the table.
We have been grappling with, for some time now, to
make end roads into the streetlights. We are
hamstrung or find it frustrating, that there are
franchise agreements which allow municipalities to
essentially -- I hope I'm not conveying information
incorrectly, so please feel free to correct me, but
essentially the electricity that's being provided to
streetlights is at no cost to municipalities. So
there is little, if any incentive, for them to take
advantage of our programs to make their streetlights more energy efficient. The other side of the coin, is that in instances where they're not receiving, for lack of a better expression, free electricity for their streetlights, they are taking a public right-of-way payment, which is generally being used to shore up their general operating expenses. So again, there's a disconnect there between the great opportunity to take advantage of an energy efficiency for a streetlight.

There's also emerging technology for streetlights, everything from -- well, obviously, LED lights, which are more energy efficient, but as well as the ability to be able to dim lights gradiently at different times of the day, or even when the street is not being used either by pedestrians or vehicles.

CHAIRMAN SCOTT: Let me ask one more question while we've got you.

For the municipalities or local governments that operate them, water and wastewater treatment plants are probably the single biggest user of electricity that they've got. And very often, the
decisions on where to spend money in municipalities makes it very difficult to, you know, to do new capital, to do that.

Do you guys have anything?

MR. MEL NICKERSON: Yeah, thank you --

CHAIRMAN SCOTT: -- or have you thought about --

MR. MEL NICKERSON: Fair enough, thanks you for asking. Actually, I want to thank you, Chairman Scott and the Commissioners, for approving our wastewater treatment program. We're really excited about it, it's aptly named the Clean Water Energy Efficiency Initiative. The governor has put forth an initiative which combines both a revolving loan fund, that's administered the Illinois EPA, the Illinois Environmental Protection Agency. And we are augmenting that program ultimately to serve that constituency. That sector accounts for 35 percent of all of the energy that municipality consumes. So we focused a particular program that looks at the most energy-intensive portion of that operation, which is the aeration system. In technical jargon -- it drives out the sludge, shall we call it in polite
But we've have got a great program there and we don't necessarily see the similar type of impediment in the waste treatment area as we do for streetlights. They are a revenue generating entity for municipalities; so therefore, they have their own budgets. Our biggest constraint now is one, getting the fiscal year cycles aligned; people want to do these things but there's a timing issue there. And then secondarily we just need to get the word out, and so we are working on as well. But we thank you for the opportunity to move forward with that program.

CHAIRMAN SCOTT: Let me turn to Mr. Potach and then I'll come back to you, Mr. Cuttica. It's very intriguing what you're talking about with outset programs. In most states, because they're not talking about doing things with respect to greenhouse gases until now, haven't tried to figure out ways to account for what's going on our there.

So could you maybe tell me a little bit more, in the same vein, about where you think the
privately run programs can go. And then, what's the best way for us -- you're talking about the DOE platform, but how best we would we incorporate something like that?

MR. JAMES POTACH: So one is that the Energy Savings Performance Contract end market, ESPC, is a very established market that's been around for over 30 years. It varies on the level of adoption, state by state, and in my opinion is, it's more about time and expertise and then policy to back that up. So in states where you see strong sponsorship, Alabama's an example right now, very active in that space. California has a history, Texas has a history, Pennsylvania has a history; you can go around the country and those that have adopted and sponsored and driven legislation drive results in their geography.

CHAIRMAN SCOTT: What drove it -- it's probably different in every state; but what drove it in those states?

MR. JAMES POTACH: I'm a business guy, not a policy guy unfortunately, so I can't really tell you, but I think once somebody -- I'll answer it in kind
of a backwards way. The opportunity is -- I mean, it's hard to even calculate what the opportunity is because it's so unscratched at the surface, at the federal level and at the at the state level. So I think once somebody decides they can get behind it and then leverages outside expertise, candidly, to help write or create a framework to make it practical and make it happen, that's what we have seen has been effective. So with some of these other member companies, we've written this kind of simple ten-step framework for a state to deploy, but more importantly, to really urge the EPA to be specific about guidelines because the feeling is if you don't make the EPA be very specific about what qualifies and what doesn't, it'll just kind of be forgotten at the state level or lost because people are unsure; they don't know how to get it done. But if we provide a framework then states can execute. You'll see states extremely active, it's actually just started to get active here, in the City of Chicago, in the last 6 months or so.

So I think it's as much as anything
relying on -- there's a coalition or -- not a
coalition, there's a group of escrows that works at a
federal level and a state level that can help create
a framework. And ironically, water treatment
plants -- another opportunity that we need -- it's a
third of the consumption of a city. There are old
facilities that have maintenance that they keep up
with because they don't have the funding and they're
effectively turning that energy into an asset to redo
the infrastructure of the facility and dramatically
drop the energy consumption.

So if you talk about a small city or
municipality you had one-third of their consumption
in one place, and that's -- that's a major impact.

CHAIRMAN SCOTT: And for the kinds of programs
you're talking about, in addition to things like
municipalities, are you mainly talking about
industrial uses?

MR. JAMES POTACH: The ESPC market is
candidly -- is primarily executed in what -- it's a
really crummy acronym, it's called the MUSH Market.
So it's -- think of federal, state and municipal,
institutions, public universities, public hospitals, it's implemented in that market because those institutions, they don't have the time or the expertise, and they can tolerate a long pay-back cycle for very, very deep energy retrofits over 10 or 20 years. And the escrows stand behind them, they financially guarantee results.

Industrials just kind of do it on their own: They build plants, they make manufacturing alliances, they say we'll do it on our own or we'll fund it. They have a -- candidly, they have a tighter -- they have a shorter -- they won't invest for 10 or 20 years because you're competing with marketing dollars to, you know, make cars or sell more drugs or whatever it is. So it's different in the private versus the corporate sector.

CHAIRMAN SCOTT: Let me direct that to you back to you, Mr. Cuttica, too.

So one of the issues that we've heard about frequently is the one that Mr. Potach just brought up, which is people aren't doing these programs because the return on the investment is too
long. It takes too long to do that and you're competing with other things.

Is that an issue in CHP and other states that have adopted their program more robustly than we have today?

MR. JOHN CUTTICA: Well, I guess again, it depends on the sector you go after. Certainly the industrial sector has a requirement for shorter payback periods, but, again, the CHP market does go after the large commercial and institutional, which can stand the longer paybacks like the ones that he was referring to, the hospitals and what have you.

But in the industrial sector, I think we see the largest percentage of CHP installed in the country today is in the industrial sector, but it tends to be in the very large industrial home -- area. But the simple answer to your questions is, it is a barrier. You have to get that payback period down to something reasonable.

I'd like to make two other points.

CHAIRMAN SCOTT: Sure.

MR. JOHN CUTTICA: Everybody asks all the time,
1 what is the economic potential; what is economic.
2 I can tell you that after things like
3 Super Storm Sandy and what have you, that what a lot
4 of industrials as well as institutional facilities
5 felt was not economic before those storms, all of a
6 sudden after the storm it becomes economic because of
7 the characteristics of the CHP system. So again,
8 if -- it has the ability, if it's installed for this
9 purpose, can ride through some of these prolonged
10 outages. So again, it really depends. So I hate to
11 answer your question with "it depends" on the
12 industrial facility: what they're looking for; what
13 their needs are; if they're going to lose their
14 product if they have an outage, and all of a sudden
15 that six-month or one-year payback can be extended.
16 If you would bear with me, I'd like to
17 build on something that Melville said before on the
18 wastewater treatment. What's really encouraging to
19 me in that whole wastewater treatment -- and I want
20 to bring it back to the industrial, is that what's so
21 good about the program that he's put together is that
22 it goes after the process. It doesn't go into a
facility -- a wastewater treatment facility and says,
We're here to sell you energy efficiency; let me
change your light bulbs. It talks about their
process -- their aeration process or their
de-watering process, which is what they are really
interested in, and then it looks for what's the
energy efficiency gains associated with those
processes. I'd like to bring that over to the other
side, the industrial. That's what I think has been
lacking in the past, which really needs to be pushed
for the future potential of energy efficiency. And I
take my hat off to both utilities this year with
their large CNI program that starts to get to that.

But there are other reasons in my mind
why it hasn't been able to be pushed as much in the
past. But, I think for the potential in the future,
the industrial is the place to go. And the way to
get to the industrials is not to -- we can sell them
light bulbs, but what really we got to get after is
their processes and how to make their processes more
efficient.

CHAIRMAN SCOTT: I appreciate that.
You got just about ten minutes left.

I don't know if -- without getting into a whole other area, but let me just go around the horn and ask -- take a couple of minutes and tell us a couple of things that you think either we could do or what would be some process changes in the way we operate now in terms of the programs. Some of you have hit it on some of them as you went around; but a couple of things that you think that we could do more to maximize what we're getting out of the EE while protecting the customer interest and everything that we talked about.

So we'll start with you, Mr. Martin.

MR. KEITH MARTIN: Yeah, I think Craig touched on it. Certainly we need some legislative changes, I think we're all aware of that. I think also some very clear rules on how we quantify savings, the inputs to the cost-effectiveness test -- you know, laying out a good plan is critical and then having stable budgets for that plan is critical to really put these programs in the market and make them effective. So clear rules, clear legislative
framework I think are very important and very
critical.

CHAIRMAN SCOTT: Mr. Jensen?

MR. VAL JENSEN: A couple of things brought up
by both the folks at Ameren and Becky or Annette.

As we try and look under every rock to
find the next batch of efficiency, it would be
helpful to us -- and I sit in meetings with our CFO
all the time, and you listen to how much money we're
losing as a result of this. The latest estimate, $10
plus million dollars, as a result of the lost revenue
from the energy efficiencies. So at least opening a
debate about how we could incentivize that, and then
I think the suggestion of taking longer live measures
and amortizing those would be one that we really
would like to explore.

The second piece, which you've alluded
to, Chairman, is how we blend these two processes
together. I think we've started to try and figure it
out in the last planning cycle but I'm not sure we
can wait another three years before we sort of figure
out what we're doing here. And I think it can have
some pretty big implications for residential and
small commercial customers if we can't figure out how
to balance these portfolios.

To Becky's earlier point about
Massachusetts still being below avoided costs, that's
ture, but it's very expensive in terms of the actual
dollars being expended. When we moved our lighting
portfolio under the IPA, we replaced it with a white
goods program that costs something like a dollar of
first year kilowatt hours saved, relative to a
lighting program that was saving at 17 cents. So it
is more expensive even though it may still be
cost-effective. So finding a way to balance those
two efficiency funding mechanisms will be very
important for us.

CHAIRMAN SCOTT: Appreciate it, thanks.

Mr. Potach?

MR. JAMES POTACH: I would say, You have
legislations to supports performance contracts. I
would say, just set targets. It's pretty straight
forward. In the public sector in every state and
especially at the federal level as well there's just
this aging infrastructure of buildings that -- I
mean, what federal, what state building have you been
in that's been built in the last five years? They're
older buildings, so they're ripe for enter -- they're
the best portfolio, it's right for energy efficiency.

I'd say that's 1. And then 2, as I
said earlier, I think you've got an opportunity with
this 111(d) rule to really urge the EPA to write some
specific guidelines, and we've presented that
actually at the national NASIO conference, the state
energy efficient conference and also presenting that
to the EPA. So I think you got a vehicle you can
leverage, but they just need to be specific.

CHAIRMAN SCOTT: Mr. Cuttica?

MR. JOHN CUTTICA: Well, I have to end on
combined heat and power --

CHAIRMAN SCOTT: I'm glad I'm sitting down.

MR. JOHN CUTTICA: People think that those are
my initials.

But first of all, I'd like to see CHP
on a much faster track, especially with the
utilities. I think they're moving but I'd like to
see it a lot faster. And I take my hat off to DCEO to get out front with the pilot program. And the second thing actually related to CHP is, I'd love to see waste heat to power as an allowable technology under the renewable portfolio standard. Not that waste heat to power is a renewable technology, but it certainly has the characteristics of a renewable, and there are at least 11 states where waste heat to power is considered at technology allowable under a renewable portfolio standard.

CHAIRMAN SCOTT: Thanks.

Ms. Stanfield?

MS. BECKY STANFIELD: All right. Five things very quickly.

Address the way the benefit side of the equation and the cost benefit analysis is being underestimated by including both non-energy benefits and the price suppression effect. We need bigger budgets, particularly for industrial and commercial projects so find a way to align the budgets with the cost-effective potential.
For programs that really depend on joint delivery between gas and electric programs, we need to figure out how to allow those programs to go forward, given those constrained gas budgets. And that may mean moving for some programs to a fuel-neutral way of counting savings. It may mean just allowing electric utilities to take credit for gas savings programs like from multifamily affordable housing where gas is such a big part of the accretion.

For heaven's sake, show the real cost of energy efficiency if you're going to put the cost on people's bills. When I hear people say, This is expensive, I always have to think, Relative to what? Because if you do not do it then you have to do something. And by definition the savings that we're getting with this portfolio and the ramp up is less expensive than the cost we're avoiding.

And 5th, we do need to figure out how to provide an earnings opportunity for utilities that are meeting and exceeding their goals. And to really align the utilities incentives with making energy
efficiency the core resource choice in Illinois.

CHAIRMAN SCOTT: Thank you.

And Ms. Beitel?

MS. ANNETTE BEITEL: My comments are not going
to repeat what others have said, but I'd like to
focus on some changes to the regulatory process that
I think would be helpful.

Number 1, Illinois really needs a
consistent set of policies that cover all the program
administrators, specifically in the form of policy
manual. So just by way of example, each of the
programs or portfolio administrators have slightly
different policies that the ICC has mandated around
the treatment of net-to-gross ratios. And it's
really hard and inefficient to work with all these
different sets of policies. We need just one set of
policies for all of them.

Number 2, I think it would be helpful
to have a longer planning horizon. So right now
these plans in Illinois are filed every three years.
And there isn't necessarily a big difference between
plans filed every three years from what came before
the prior year. I'd like to see the planning horizon maybe extended to 5 years. I think maybe that's a statutory change. Other jurisdictions are going to 5-year planning horizons, 10-year planning horizons, but they're enormously costly and I'm not sure there's a huge benefit, and it's also a lot of litigation.

Related to that, when the plans are filed, I'd love to see those dockets consolidated so there's a single consistent treatment of all the issues that are raised, many of which are common cross-holds of portfolio administrators.

And finally, and again, I think this would be statutory, Illinois seems to spend a lot of time and money looking at reconciliation on an annual basis. So specifically, which costs are allowable and not allowable. Other jurisdictions do not have annual reconciliation proceedings. What they do is they very, very clearly define in a policy manual what costs are allowed, what costs are not allowed. So there's a very clear rules of the road. And, at the end of a program year, or at the end of a couple
years, an independent auditor will come in and just
determine whether or not the cost that were
attributed to the EEPS funds -- or the balancing cut
funds met the standards. And that's just much lower
cost, much more efficient. And then everybody knows
what the rules are; what's allowed, what's not
allowed.

CHAIRMAN SCOTT: Thank you.

Mr. Nickerson?

MR. MEL NICKERSON: Thank you.

You know, I apologize. It's a
complete mistake on my part, I should've told you my
friends call me "Mel."

Four quick points. I echo the
sentiments and the statements that have already been
said about the utilities, both Val and Keith. We
need to look again a the gross-to-net way of
evaluating our programs. I think that clearly 111(d)
has raised a very sobering issue in that under 111(d)
you don't care about net, what you're looking at is
gross. And I think we, going forward, that is
something that we should grapple with under or EEPS
Secondly, I also agree that amortizing the savings over a number of years is also critical because that is the whole picture -- or the whole truth. The savings that are being generated don't just occur in one year, they have a longer period of savings.

I also want to say that I'm very grateful to the Commissioners for approving, along with the utilities, a program which we've been calling the Codes Enhancement Program. Essentially what that is that we have a law on the books, passed in 2009; we have a state-wide building code, both for residential as well as commercial. Little known secret or maybe not, there is not state-wide compliance with the program. Part of it is due to -- lack of better word, ignorance on the part of local governments. More importantly, it's a lack -- let's say a lack of resources. So we are embarking together as a coalition to address these issues. To help move the needle from the baseline to what the potential is.
I'm very proud to have worked with Midwest Energy Efficiency Association. They did a preliminary study which indicated that if we could move the baseline what it is now in terms of building code compliance, to just state-wide compliance with what is the law, it would generate 12 gigawatts of savings. So you can take that to the bank, so to speak.

I'm also going to end on CHP, John. I'm very thankful to you and your colleagues for putting forward just a brilliant opportunity to help advance Illinois in that area. It is something that's being recognized nationally, so due credit to you. We are, if you will, willing partners but more like a conduit to this good end.

One thing I would like to comment on because it has come up both in our recent three-year plan and also, now, unfolding in our -- in the upcoming workshops in the Senate. There is a question of how you count the savings generated post the CHP retrofits. There is some concern back and forth among stakeholders, not to count the full
amount of energy efficiency that is gained or the increased amount of gas usage. Simply put, the General Assembly made a definitive recommendation, which is now law, which is that the BTU savings should be counted period. That could have said "Count kilowatt hours," they didn't say that. They could've said "Count Term Savings," they didn't say that. They took a comprehensive look and said when it comes to CHP, or when it comes to this type of endeavor involving CHP, you should look at BTUs.

So on that note, thank you very much.

CHAIRMAN SCOTT: I want to thank all the folks, who talked to us today. A lot of great information, we really appreciated it and did fully what we needed it to do. Thanks very much to Carla and Suzanne for helping to put this together and making it run very smoothly today.

I want to thank the representatives who are here today, Representative Gabel, Representative Nekritzon, thank you very much for being here. And our sister agencies, IEPA and DCEO and the IPA who've been -- who are all working, as we
said earlier, together on this. So appreciate that everybody's involvement very much.

Thanks again. We'll see you back here on November 6th. Meeting is adjourned.