

Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures (Text Version)

Below is the text version of the Webinar titled "Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures," originally presented on September 26, 2013. In addition to this text version of the audio, you can access a PDF of the slides, a resource document, and a recording of the webinar in the [events listing](#) for the webinar.

Operator: The broadcast is now starting. All attendees are in listen only mode.

Johanna Zetterberg: Good afternoon, everyone. This is Johanna Zetterberg. Thank you so much for joining us today. We are going to go ahead and start the webinar on time today at 2:00. My name is Johanna Zetterberg, as I just mentioned. I am the coordinator of the State and Local Energy Efficiency Action Network, which is a joint effort facilitated by the US Department of Energy and the US Environmental Protection Agency.

Today's webinar is on using integrated resource planning to encourage investment in cost effective energy efficiency measures. We also have Devin Egan broadcasting live with us from the National Renewable Energy Laboratory, and a great lineup of speakers today. We have Larry Mansueti, the director of the State and Regional Assistance Program in DOE's Office of Electricity Delivery and Energy Reliability. We have John Shenot, an associate at the Regulatory Assistance Project, and former policy advisor to the Public Service Commission of Wisconsin. And we have two speakers from Consolidated Edison, Michael Harrington and Ronny Sandoval. Michael Harrington is the manager of the Targeted Demand Side Management Program, and Ronny is a senior specialist in that same program.

As we give folks a few more minutes to call in and log on, Devin is going to go over a few housekeeping and logistical items, and then we'll get going with the webinar. Devin?

Devin Egan: Good afternoon. First of all, you have two options for how you can hear today's webinar. In the upper right corner of your screen there's a box that says audio mode. That will allow you to choose whether or not you want to listen to the webinar through your computer speakers or over the telephone. As a rule, if you can listen to music on your computer, you should be able to hear the webinar.

If you have questions during the webinar, please go to the questions pane in the right hand box on your screen. There you can type in any question you may have during the question and answer segment at the end of each of today's presentations.

And after today's webinar, you'll be prompted to complete a short poll. Please take a few minutes to submit your answers once the webinar has ended. Today's webinar will be posted online on the SEE Action website. Once the presentation is posted, you'll receive a link to it via email when it's available. Please note that this process can take approximately two to three weeks.

So with that, I will turn it back over to Johanna to introduce Larry Mansueti for opening remarks.

Johanna Zetterberg: Thanks, Devin. So today's webinar is part of a series that supports SEE Action's efforts to take energy efficiency to scale through state and local actions. The network is composed of more than 200 leaders from state and local governments, associations, businesses, non-governmental organizations, and their partners. And I see that we have several members of the network registered for today's webinar, so welcome, everyone.

SEE Action offers information resources and technical assistance to state and local decision makers as they seek to advance energy efficiency policies and programs in their communities, and today, we're going to be talking about one of those resources that was published a year or two ago. It continues to be a great go to resource on integrated resource planning.

So I'd like to remind you that we'll be doing Q&A after each presentation, so please don't be shy. Go ahead and submit your questions at any point as you have them in the little question box, and we will get to them after the presentation.

So now I'd like to introduce Larry Mansueti, who will give us a bit more context on the guide and integrated resource planning. Larry, over to you.

Larry Mansueti: Okay. Thanks, Johanna. Larry Mansueti from the Department of Energy, and I think – could we go to the slide that covers the guide, if we haven't yet? Let's see. That one right there. Yes. And what we're going to talk about is this – using integrated resource planning to encourage investment in cost effective energy efficiency measures, this guide that was written for this particular part of SEE Action that deals with regulatory issues surrounding

the use of rate payer funded energy efficiency, whether it's rate payer funded from a gas utility customer rate payer or a electric utility rate payer.

And the guide, what we'll talk about is – well, obviously, at the beginning, we'll have a definition of what is integrated resource planning, why it's used, how it's used, how it can be used – the main subject of today's webinar, how it can be used to deal with energy efficiency as an energy resource. And how our IRP can be done differently or alternatives to it in states that have competitive retail electric or gas markets. That's pretty much in the East. That's an important distinction to make.

And then some examples of successful IRP efforts, case studies and so forth, and how IRP can work with and interact with other energy efficiency policies and programs.

The subject of or the methodology of integrated resource planning has been around, oh, roughly about 25 years, the latter half of the 1980s or so. It's evolved in a number of ways, not just how you do it, but also how it's used in different states and so forth, utilities. And also some particularly newer, more recent ways, in particular a really neat, at least from my standpoint, way, we'll here from our ConEd speakers.

And we're going to cover all of this, so I'll stop there and introduce our speakers. Our first one will be the report author, John Shenot, from the Regulatory Assistance Project, and he'll provide a summary of the report and its recommendations as well as additional resources. His writing of the report was guided by a working group that was chaired by Kit Kennedy of NRDC. Why don't we go to the next slide?

And the next slide will show who was on – the various working group members for this particular guide. And this was done on a consensus basis. Also with us will be Michael Harrington and Ronny Sandoval from ConEd, Consolidated Edison, and they're going to look at a real world example of how they're using at ConEd best practices in distribution utility planning in a competitive retail market. So from my standpoint, this is state of the art in the practice of IRP, what they're doing there in New York City.

So with that, I'm going to go ahead and introduce our first speaker, John, and he's going to take it away from here. Welcome, John.

John Shenot:

Thanks, Larry, and hello, everyone. This is John Shenot from the Regulatory Assistance Project, and give me just one more second here. All right. So today I'm going to talk about the SEE Action paper on integrated resource planning, and my prepared remarks are going to focus on the highlights of the paper. I'm going to try to stick to the consensus conclusions that were reached by our working group and avoid my own opinions, though they're pretty much the same as the consensus conclusion.

So let's begin by talking about the purpose and use of integrated resource planning, or IRP. The whole point of IRP – there we go. The whole point of IRP is to develop a sensible plan for meeting future energy needs. And by sensible, what I mean is a plan that will meet consumer demand safely and reliably and will minimize costs while taking into account risks and uncertainties. The I in IRP stands for integrated, and what that means is the planning process considers all of the available options, supply side options, like building new power plants or transmission lines, and also demand side options, like energy efficiency.

Who does this planning? Well, IRP is fairly common, but not universal, among electric utilities. It is much less common among gas utilities, and lot of my remarks are going to focus more on the electric utilities than the gas utilities. There are also a few cases where the planning is done not by a utility, but by some other organization, such as a regional planning council.

IRP is mandatory in some states, and this means that utilities have to file their plans with the state Public Utility Commission, and update them periodically, usually every two or three years, in almost all cases. In some states, the Utility Commission has to approve the plan, while in other states; the Commission just acknowledges that the utility met its obligation to file a plan. But either way, when this process is over, what you have is the utility's long-term plan for a acquiring the resources necessary to meet customer demand.

This map shows the states that have some form of mandatory planning process for electric utilities. And I want to note that this is an updated version of the map in the SEE Action report. It's not the same as the map in the report. But this one contains more current information. What it doesn't show is the states that also have planning requirements for gas utilities, and there's about a dozen of those.

The states shown in blue have a mandatory IRP requirement, while the states in green have a similar planning process, which is mandatory but isn't exactly what we'd call IRP. And one reason that a lot of these green states don't require a full-blown IRP is because the utilities in those states have a different role, as I will explain.

As most of you know, many states have created competitive retail markets for electricity, and the light blue states in this map are those where consumers can choose to buy their electricity from a competitive supplier instead of their local utility. To be clear, there are still utilities on those states, but they have more limited responsibilities, and that's why they end up as green on the previous map, rather than blue.

In these states, the primary responsibility of the utility is to deliver electricity from a competitive supplier to the consumer. In addition, except in Texas – Texas is always unique – those utilities are also responsible for procuring energy on behalf of what are called default service customers or a different term that has the same meaning, and that means customers who haven't chosen a competitive supplier, but continue to be supplied by the incumbent utility.

Now in states that allow retail competition, utilities don't do a full-blown IRP because they aren't responsible for meeting all of the future customer demand. However, they may still be required to develop a long-range plan that identifies a portfolio of resources they'll use to provide default service, and the transmission and distribution resources that are needed to deliver electricity to consumers.

Anyway, for the remainder of my remarks, I'm going to gloss over some of the differences between the competitive retail states and the other states. As shorthand, I'm going to refer to all of the ones that have a planning process as IRP. And as Larry said, the goal of SEE Action is to promote – I'm sorry, as Johanna said, the goal of SEE Action is to promote the acquisition of all cost effective energy efficiency. So I'm going to use this slide to explain how an IRP can be a powerful impetus for promoting energy efficiency.

This chart shows the federal government's estimates of the levelized cost of producing electricity from different generating technologies. And here, I've superimposed the average cost based on the number of different data sources of saving energy via energy efficiency. Although we know the amount of available

energy efficiency will vary based on local circumstances, we know that some quantity is virtually always available at a lower levelized cost than any of the supply side alternatives. So any planning process that requires utilities to consider demand side resources as part of an integrated strategy to meet demand is almost by its very nature going to promote energy efficiency.

The SEE Action paper identifies three prerequisites for successful IRP and also a number of best practices, but I'm going to start with the prerequisites. These are things – if the planners don't get these right, the plan will be kind of fundamentally flawed. The first prerequisite is to use credible forecasts of customer demand. Load forecasts lie at the heart of the planning process, and if the plan is based on unrealistically high or low expectations about future demand, everything that follows is going to fall apart. They'll be planning for a future that isn't going to happen.

The second prerequisite is to have credible information about the costs and the availability of different types of resources. It's particularly important to use recent data. For example, the cost of power produced from natural gas or solar panels, both of those have declined substantially in the past five years. And if you use older estimates of what these resources cost, you'll be way off.

On the demand side, availability can be just as important as cost. For example, you want to have a recent potential study that tells you how much energy could be saved with cost effective measures, like the kind of thing that's in this graph. And then the third prerequisite, of course, is that the planning process has to allow for fair consideration of all the resources that could potentially meet customer demand. In particular, as we emphasize in this paper, the process has to allow demand side resources, like energy efficiency, to compete with supply side resources on an equal footing.

So those are the minimum prerequisites for a good IRP, and now I'm going to take it to the next level and summarize what our working group found to be the best practices.

First, I already said that you have to have a credible load forecast, but the best IRPs model a range of possible forecasts, and not just the one case that the planners consider most likely, which we'll call the reference case. And modeling a range of possible forecasts allows them to discover whether the optimum resource plan would change if the reference load forecast proved inaccurate.

Second, the best IRPs model a range of possible costs for each generating technology, taking into account uncertainty about things like future natural gas prices, for example. Third, the very best IRPs consider the possibility that new transmission and distribution lines or improvements to existing lines can reduce the cost of meeting future customer demand.

The fourth best practice of course has to do with the demand side resources, and since energy efficiency is the focal point of the paper and of today's webinar, I'm going to spend just a little extra time on this one. Many resource plans look at energy efficiency in a static way. The planners figure out how much energy efficiency the utility has to do to meet a mandatory state efficiency policy, for example, and then they subtract that mandatory amount of energy savings from the load forecast. If there's still a need for additional resources to meet demand, from that point on they look only at supply side resources to fill the gap.

Now let's contrast that with best practices. The best IRPs acknowledge that the availability of demand side resources depends on prices. If energy costs \$0.12 a kilowatt hour, more things are going to be cost effective than if energy costs \$0.06 a kilowatt hour. So what the best IRPs do is create cost curves and allow the model to decide how much efficiency should be in the plan depending on future prices and costs. And the plan will of course include enough efficiency to meet minimum statutory requirements. That's not optional. But if additional efficiency is available at a lower cost than other resources, then that should be part of the plan, and in the best IRPs, it will be.

The fifth best practice relates to environmental regulations. It's true that none of us knows with certainty what future environmental requirements will look like, but the planners will always make their best guess and put that best guess in the reference case. The best IRPs, however, will take into consideration a range of alternative future environmental requirements, and consider what it might cost to comply with those if they bear out.

So for example, the planners might decide not to put a price on carbon emissions in the reference case, if they think that's not the most likely future, but they'll still model alternative scenarios where a carbon cost is imposed, and that will reveal any vulnerabilities they might have to a future that is not what they expect to be most likely, but is definitely a possibility.

The sixth best practice has to do with modeling. The best IRPs evaluate the cost of multiple possible resource portfolios, and by portfolio, what I mean is a mix of resources that could potentially meet customer needs. Each portfolio is then assessed not just once for the reference case, but under multiple what if scenarios, using different assumptions about things like customer demand, about energy prices, environmental regulations, all the – all the variables.

So what they end up with is a matrix of the estimated cost of different portfolios using different assumptions about future conditions. Then, and then, and this I think is really the essence of best practices, the planners identify a preferred portfolio that is robust, and by robust, I mean it keeps costs low under all or nearly all of the scenarios. It doesn't necessarily end up being the cheapest portfolio under reference case assumptions, though it will probably be pretty close. But it might be close to the cheapest under reference case assumptions and yet have – provide a much better hedge against some of the uncertainty that appears in other scenarios that have been modeled.

Seventh, the best IRP processes provide an opportunity for stakeholders to review the data assumptions that go into the plan, and the list of what if scenarios that will be considered, and make sure to also get the chance to suggest changes or additions. And finally, stakeholders should be given the opportunity to review the modeling results before the plan is finalized.

And finally among best practices, the best IRPs will acknowledge how the electricity sector actually works and they'll model at a regional scale, if that's feasible.

I want to briefly mention a different report on IRP best practices that was published more recently than the SEE Action report, and the sponsors of this webinar said I could mention it. This report was produced by Synapse Energy Economics for RAP, where I work, and I encourage you to download a copy of this report after you download the SEE Action report, of course. I think you'll find that the two reports complement one another, and they reach entirely similar conclusions about best practices. I don't think there are any contradictions.

Lastly, I wanted to leave you with some examples of best practices in action, and rather than go into the details of any of these, I'm going to mention them. I'm going to refer you to the report. I think virtually all of these you can find their integrated resource plan on their website. And instead, what we'll get is a great

detailed example of one of these from the next speakers, from Consolidated Edison.

In the SEE Action report, we featured great work on IRP that's being done by the Northwest Power and Conservation Council for the Bonneville Power Administration. And we featured the IRPs of Pacific Corp, a utility operating in six western states, and the work for Con Edison that you're going to hear about.

The more recent Synapse report also featured Pacific Corp, but in addition, it highlights some great IRP work being done by Arizona Public Service and by Public Service Company of Colorado.

And that wraps it up for me. My contact information is here, and I want to thank you all for the chance to present today. I think I've left a few minutes to take questions before we hear the presentation from Con Edison. Johanna, have we received any questions?

Johanna Zetterberg: Thanks so much, John. Yes, if anyone has any questions for John right now, in addition to being able to contact him offline with his contact information here, please go ahead and submit those questions into the question box in your little control panel as part of the webinar, the GoToWebinar.

As you all are typing in a few questions, I just want to remind folks that all of today's presentation will be posted on the SEE Action website within a couple of weeks, and we will let you know when that is available for download. It's a large file, so we'll let you go get it on your own, as opposed to clogging your inbox.

The bonus resource that John just spoke of is available on the RAP website, and the SEE Action IRP paper that is the topic of today's webinar is available on the SEE Action website, which is SEEACTION.Energy.gov. And you'll need to go to the working group page that produced the paper, which is the Driving Rate Payer Funded Efficiency through Regulatory Policies Working Grouping, so if you find that working group page, you'll be able to locate that paper as well as other useful papers.

John, I don't see any questions in at this time. We can entertain questions at the end of the ConEd presentation as well for you. So why don't we move now to ConEd's presentation? So over to you, Michael Harrington and Ronny Sandoval from the Energy Efficiency and Demand Management Program. Thank you.

Michael Harrington: Thanks, Johanna. So this is Michael Harrington with ConEdison. I'm joined by my colleague Ronny Sandoval. And we're going to spend the next 15 minutes or so walking through ConEdison's processes and planning and programs for integrating energy efficiency into our system planning.

Everyone see my screen okay, I assume? I got it right? So we're going to talk about three things, really. Just kind of a level set for who ConEdison is. You know, what we're concerned about, what we're looking at, to provide some context to the following deep dives that we're going to go into, into how we integrate demand side management, energy efficiency, demand response into our system planning. Ronny's going to present that, and then I will come back to the presentation to do a deep dive into our targeted DSM program.

So a little bit about ConEdison. I think the takeaway here is obviously we serve a relatively small service territory, especially compared to a lot of our fellow utility colleagues, but it's very dense. There's a lot of people, a lot of buildings, a lot of load, obviously, in our area. So those – the density, certainly the critical nature of a lot of the industries that operate in New York City, and the population, are things that provide particular opportunities and challenges for us as we think about demand side management in our planning. Certainly it's something that our engineers focus very heavily on, in developing and maintaining and upgrading our distribution system, and certainly something that we take into consideration, of course, in our planning and our programs.

So of course, you know, most of the people on this call, and certainly we agree, there are a variety of benefits of energy efficiency and demand side management. Certainly, the five here that you see are pretty standard. The focus for us moving forward in this presentation and certainly in our programs is the transmission and distribution savings, so the T&D portion. So we do recognize all of the values across the supply chain that energy efficiency provides, but we're going to talk very specifically about how we – how we capture those benefits on the T&D side, of course, in our engineering and planning.

Just a quick level set for where ConEdison plays. This is a pretty generic diagram of the supply chain, of the electric supply chain, from central generation through bulk distribution through the transmission system, and of course, through the distribution system. Here in New York, we are deregulated, and we – ConEdison, since the late nineties, has operated just the

distribution system, so essentially from the area substation to the customer meter. So the issues and opportunities that we're talking about are focused in the distribution system, and not focused on bulk transmission, resource issues, and generation resource issues. So that's a little bit different than what you may hear from the California utilities and other utilities that are looking at demand side management solutions to meet the needs of generation retirements and transmission constraints. So just wanted to kind of set that as the playing field for what we focus on in our efforts.

So we have been doing this for a while, but, you know, we're not – we're not old grizzled veterans yet. But in 2000, the market obviously restructured here in New York, and generation and transmission and distribution were kind of all separated. ConEdison divested all of their upstream assets. Moving shortly from there, we actually initiated the targeted program in our demand response program. So we've been in kind of the demand management game. We were – in the seventies and the eighties and then the nineties, and then back in the early 2000s.

We moved forward into a situation where we have a variety of energy efficiency programs now, which Ronny will talk in more detail about how we integrate those into our planning. And of course, quite a few other things that we're looking at on the engineering side, and of course on the program side going forward, starting really about two years ago. And I'll go into more detail about that on the targeted DSM program.

So that's kind of the level set. I'm going to hand it over to my colleague, Ronny Sandoval, who's going to walk through how we integrate energy efficiency into our system planning.

Ronny Sandoval:

Great. Thanks, Michael. So again, this is a topic that was touched upon in the SEE Action paper regarding the integrated resource planning. That's essentially how we incorporate demand side management into system planning. So, I mean, the reason we include DSM in our system planning is that we recognize that the associated demand reductions associated with these programs could offset the expectations for future load growth. So this in turn could result in a deferral of capital investment that would otherwise be necessary in order to meet the higher load growth.

So as you can see in this slide, beginning in 2004 or so, we began to integrate demand side management into our system planning, and that began with the targeted demand side management program. So for example, once we made the commitment to say

we're going to, instead of building out infrastructure, we're going to target the demand side of the meter, to defer capital investment, we also had to incorporate it in the in system planning to ensure that we weren't overbuilding or not taking it into account.

In about 2008, 2009 or so, we had a couple of system-wide programs that weren't necessarily targeted in a specific area of our territory, but these are programs that nonetheless would have some impact across our service territory. We also looked at other program administrators, including New York Power Authorities, that NYPA. Also NYSERDA administered a few programs within our territory. And late in 2011, we began incorporating the impacts of demand response into our forecast as well.

This slide here kind of indicates our whole system planning process and where demand side management, including energy efficiency and demand response and distributed generation, fits into our planning process. So we have those components, DSM and DG, feeding into our existing peak load forecast, which is the traditional forecast that we look into based on growth projects that we know are there, as well as the impacts of the economy as a whole.

These forecasts are then made available to the various planning organizations, including the more localized regional distribution, area station planning, transmission planning, so that they can then incorporate the – you know, the total impact of the projected peak loads, not just – including the impacts of energy efficiency and distributed generation, so that they know what are the appropriate investments that could be made or should be made for the next 10 or 20 years or so.

So this one slide here, it's a very simple graph, and it very cleanly illustrates the impact of demand side management on our system forecast. So the top line, what you may see is a compounded annual growth rate of about 1.6 percent from the period of 2013 to 2022. These numbers, they'll shortly be updated, but essentially, you'll see that taking DSM into account lowers that growth rate from 1.6 to 1.2, which is a 25 percent reduction in the growth rate, which is very significant, looking forward. And that in turn could lead to a lot of deferral of capital investment.

Here you see how it – the demand side management impacts are incorporated into the planning process. Here you have a substation that's applying a local area. It looks to grow to about 216 megawatts by 2021. So the top line is the forecast without the

impact of DSM. The – you'll see that DSM is essentially subtracted from that top line to yield the net demand projections going forward. The very last line is the capacity of that substation. So you see it at about 200 megawatts capacity.

If we were to just plan it out using the forecast without DSM, you see that by the year 2014, we probably would have to make some sort of investment or have some investment in place in order to meet the growth in demand. But by incorporating demand side management, as you see in the third line, we're able to defer that investment or the need for that investment by a number of years. So now instead of 2014, it's 2018, which definitely there's some demand savings and capital investments that would have been deferred by then.

Lastly, I'll just briefly go by our process for forecasting. So it isn't enough to just say this is how much is happening. We typically have to identify the areas where the demand side management would occur. That way, we know which investments, which area stations are being deferred, which transformers, feeders, things like that. So the first thing we do is we allocate those energy savings to a particular area of our system. We then convert the energy savings to demand savings, based on the different measures and customer segments that we target.

And lastly, we do, because some of these programs, specifically the system-wide program, are not allocated or not mandated to occur in one particular area of a system, we do some accounting of the variability of where those savings will occur so that we – you know, we're not taking a lot of liberties, and we show some level of conservatism when planning out the system.

Lastly, this is just a graph of what I just mentioned. Essentially, we have different customer segments. You see residential, multi-family, small commercial, and large commercial. Depending on the measures and the customer segments, the peak demand reduction would differ over the course of a year, over the course of a day. So we try to take those into account, how the energy conservation measures behave during the peak time when we're making our projections, and actually when we're designing our program.

Lastly, we – by incorporating demand side management into our system planning, we're able to be a little bit more accurate about where the growth is happening and what the load is over a period of time. We – over time, we've also made some improvements in

the accuracy of the forecasts, which has given some level of comfort to the engineers in the planning group. And also, as we – because it's – the demand side management is explicitly stated and included in system planning, there's a increased level of awareness and interest in including demand side management and all its aspects in system planning.

At this point, I'll turn it over to Michael, who'll talk a little bit about the targeted demand side management in particular.

Michael Harrington: Thanks, Ronny. So I'm going to do a deep dive into the targeted program. Of course, we'll have time for questions on what Ronny presented at the end of the presentation. But I wanted to take an opportunity to dive into one particular program that kind of kicked off – well, not kind of. It did kick off this whole integrated planning process for ConEdison back in 2004. The program is one of the energy efficiency and demand management programs that we operate, but it is – it is the only program that is currently targeted specifically for T&D cap-ex deferral.

The system-wide programs, as Ronny explained, are incorporated into planning, but they're not explicitly targeted at particular projects and capital expenditures. So I'll dive right in. So the targeted program, as I mentioned, has been around since 2004. We contract specific demand reductions based on the ten year load forecast. So that would be the load forecast after accounting for the other energy efficiency programs. So the delta between what capacity the station has and what the load will be, we look for opportunities there to further push those projects out or potentially eliminate the need for large capital expenditures.

We typically target projects from transformer replacements on up to new area stations themselves, which of course are very, very expensive. There's a lot of opportunity there to push those – push those out. The issue with geographic uncertainty that Ronny mentioned is not an issue for the targeted program, so any discounts for uncertainty and that sort of thing are not required to be taken. Of course, the risks are performance, and I'll get more into the detail about how the actual reductions are implemented.

Just very briefly, the targeted program has been around since 2004. It's still around because it's been successful. These are some high level numbers about what we've achieved since 2004, 108 megawatts of demand reduction, 281 gigawatt hours of annual energy savings. Of course, we spent a lot of money, but we saved a lot of money, and I think the key takeaway here is that you see

the benefits bar on the left is much higher than the cost bar on the right. So we – it's been a cost beneficial program achieving a TRC benefits/cost ratio of over 3.

So based on those results, you know, we are continuing to look for opportunities. I'll go into more detail there in a few minutes.

One thing of note here is that some of the savings of course that we achieved were a result of the downturn in the economy. So one point to mention here that was I guess unintended by very positive benefit of the targeted program is that it actually provides a downside hedge to forecast uncertainty. So we had forecasted load growth obviously through the economic downturn, of course not accounting for the economic downturn, so we had a lot of projects that were planned to meet that forecasted future growth, which as it turned out didn't materialize. But we had quite a few targeted contracts in place that actually were intended to defer projects two, three, four years or so, and some of those projects have been deferred indefinitely, and some have been deferred more than ten years. As a result of the targeted contracts being in place, the engineers didn't plan and build, and the downturn in the economy actually significantly extended those. So that was quite a nice surprise for us.

So exactly how the targeted programs works, how do we – how do we achieve those savings? Of course, we identify the shortfalls, as we mentioned, and as Ronny showed in his previous chart. And then we work with engineers and we figure out which projects are viable. We issue RFPs to the market, and the market responds back, saying, this is how much we can do. This is what we can do it for. We select economic bids, and we contract with the vendors to actually go out and achieve the reductions.

I think one thing to note here is that the contracts are quite strict and firm, and they have 100 percent pre and post-measurement verification requirements and liquidated damage requirements, which motivate the ESCOs to meet their goals, but also protects the utility and the utility customers in case the targets are not met.

So I like graphics, so graphical example of how this actually works is we identify an area station that has a constraint. We identify what that constraint is. We go out and we contract for permanent energy efficiency measures that could address that constraint for a predetermined period of time. We also have done a pilot and are looking for additional opportunities to go into more precise

targeting of secondary and primary distribution assets, with permanent energy efficiency, again.

We think there's opportunities in the future, and we're looking very hard at those to do targeted demand, demand response, and targeted distributed generation, in addition to the energy efficiency that we have done so far.

So an example project, so this would – this would essentially come out of the – of the planning chart that Ronny previous showed. This is completely hypothetical, but of course, is high level items that we look at and we consider. Of course, we identify what the shortfall is. We contract to cover that shortfall, and then contractors go out and actually achieve those on a very rigorous annual schedule, and penalties are associated with not meeting those annual goals. And then of course you identify the costs and the benefits, etcetera, and so forth.

The features of the program, this is an important – I guess important details, is the vendors were initially fully responsible for all marketing implementation. That continued to be the case on the implementation side. The marketing side, we found that having the utility involved was a benefit in terms of customer trust and those sorts of things. So we got more involved in marketing as we went forward.

As I mentioned, the 100 percent MV requirement, quite rigorous, but we thought necessary to ensure that we were getting the reductions that we had promised to the engineers, since they were not planning to build the project that we were deferring. The liquidated damages has certainly motivated the ESCOs or the vendors to achieve. We had a limited menu of measures that were focused on kW only, so I guess that's an important distinction between this program and our other programs, which are focused on kW/h energy reductions and energy efficiency. This is focused solely on demand reduction. Of course, we get the benefit of the energy reductions as well.

And it's important to note that distributed generation was actually included and is still included as a measure, eligible measure, but we require some pretty rigorous guarantees that that load reduction will be there at all times. So no projects were actually done to date, even though DG was eligible.

Very briefly, with that setup, we let the market decide how to best achieve the reductions. We ended up getting over 95 percent

lighting reductions, which is quite interesting. We think that was the low hanging fruit, given that we were paying a set amount of money per kW. The contractors certainly went to the – went to the best and quickest opportunities.

The breakdown of the customers that we've served, about 50/50 in terms of load reductions, residential, commercial, but of course, you've got to go to a lot more residential customers than commercial to get those same load reductions. So these are actually results of the program thus far.

Key takeaways, communication between the programs and the engineers and planning groups is absolutely essential. Obviously, you wouldn't be able to get a program like this off the ground without it. Vendor management and contracts are key to make sure that the utilities' and customers' interests are covered, but also provide a fair means of generating revenue for the contractors.

Flexibility to adjust contracts as load changes. Of course, you're going off a load forecast, so it's important to be able to modify those contracts. Coordination with other programs is obviously quite important. And as I mentioned before, the utility, branding, and direct support in marketing was – we found to be quite beneficial for building customer trust and getting projects done.

Next steps for the targeted program. Given our track record, we've been approved for a new \$100 million program, which is great, but we have a lot of – we don't have a lot of load relief needs at the area station levels for the next five years. So we're really taking the opportunity now to take a – to do a lessons learned on the program since 2004, make note of where we were successful, make note of where we could improve, and then actually address those areas where we could improve.

One area I think is other technologies, knowing the customers better, knowing the area better. And then to go back to what John had mentioned previously, accurate recent potential studies. And we're actually doing that at the local network level. So we're kicking off a market research project very shortly that will be doing potential studies at the individual network level. So networks typically served by one area station, potentially two networks served by one area station. But it's a granular geographic area with specific types of customers.

On top of that, we're doing a full technology review of all energy efficiency, demand response enabling, distributed generation and

energy storage technologies that could be applicable for peak demand reductions. Those will include New York City specific prices and benefits. All of those will go together to build an integrated planning tool, which will allow ConEdison to look at a very granular level in our system to see what the customer potential is for demand reductions, what specific technologies are applicable and can contribute to those demand reductions, and of course, the cost and benefits of doing that.

And this tool essentially will be a modeling tool that will integrate energy efficiency potential and measures, demand response potential and measures, distributed generation potential and measures, and storage potential and measures, and integrate and optimize those and allow us to optimal portfolios based on various criteria, such as absolutely lowest cost, maximum amount of megawatts reduced, achieve some certain targets or maximize certain benefit to cost ratios.

So we're really excited about this project, and we think it's really going to enhance the success that we've already had for targeted, and really get us a lot closer to what the – a very granular look at the potential and customer needs and costs and benefits, to allow us to target even more effectively.

So more information about the program and about ConEdison's plannings, there's two really great articles here. I assume that this will get sent around so you can have these links to go. I encourage you to take a look at these resources here. And then, of course, we're going to field questions now, but if you don't get your questions in or you have additional questions, my contact information and Ronnie's contact information is here. Feel free to reach out to us.

That wraps up ConEdison's presentation, so I guess we'll open it up to Q&A.

Johanna Zetterberg: Thanks so much, Michael and Ronnie. We do have some questions that have come in. So the first one is for the two of you. What incentivizes ConEdison to pursue DSM as opposed to building new infrastructure?

Michael Harrington: That's a great question. So the initial targeted program included financial incentives for contracting and meeting those targets. Certainly now we have cost management directives and strategies here at the company. You know, we work very closely with our regulator to help customers reduce their costs and to manage costs

for the company and for our rate payers. So certainly, we think being able to do energy efficiency more cost effectively is a benefit to our rate payer, and certainly to the company in managing our costs.

Johanna Zetterberg: Thank you. And a related question, wondering why ConEdison uses the TRC, that's the total resource cost test, rather than other cost tests, such as the utility cost test or the program administrator cost test.

Michael Harrington: Sure. It's mandated by the State of New York, by our Public Service Commission. The TRC is the recognized and allowable and mandated cost test for energy efficiency programs. We certainly do recognize the value of the other cost tests, certainly for resource planning. I know Cadmus came out with a great white paper a few months ago about looking at the utility cost test as an option. We see the value there, but at this time, we use the TRC.

Johanna Zetterberg: Great. Another one for the two of you. How does the New York City benchmarking requirement for public, commercial, and residential buildings affect your planning process? I assume you have better prediction of DSM project risk. Does this also assist in understanding load growth in any way?

Michael Harrington: Certainly it does, in a – to the extent that it will factor into the data that we're able to collect about our customers for our research project to identify potential and that sort of thing, obviously, having better data about our customers will allow us to serve our customers better.

In terms of the forecasting process, I'm not exactly sure how they factor that information into the overall load forecast, but I don't think it hurts any to have more information about the buildings that are out there, but I'm not 100 percent sure on that. If somebody wants to send me that question to my email, I can certainly follow up and get more detail.

Johanna Zetterberg: Sounds like a good topic for a future webinar. The question came in one of your slides. It was the long term impact of DSM graph. I think that was your slide 11, if you could turn to that. Great. That's the one. So the question was does the reduction in compound annual growth rate with DSM include only current DSM programs, or does it also include incorporate potential and future DSM programs?

Ronny Sandoval: Yeah, it's – the DSM listed here is only the approved demand side management programs that we have some visibility on and we can confidently include in our forecast. And absolutely, going forward, there may be some programs that are renewed, some additional programs that are included, but in the meantime, we wanted to just concentrate on the ones that we have some visibility into as to how much is happening where and the types of demand side management measures or energy conservation measures that are included, in order to accurately and – accurately portray the behavior of demand side management going forward.

Johanna Zetterberg: Great. Thanks, Ronny. A question came in in follow-up to the question on the financial incentives. Could you just speak a little bit more about what type of financial incentives exist?

Michael Harrington: Are you talking just generally for energy efficiency in the ConEd service territory, or specific for the targeted program?

Johanna Zetterberg: Why don't you do address it more generally?

Michael Harrington: Sure. So in addition to the targeted program, ConEdison runs about a dozen other energy efficiency programs that provide incentives, measure level incentives for lighting retrofits and mechanical upgrades, those sorts of things, so pretty standard menu of energy efficiency measures that there are incentives for.

In addition to the utility, and this is fairly unique to New York, there's also NYSERDA, the New York Energy Research and Development Authority, which also operates programs in our service territory, offering incentives for a pretty standard menu of energy efficiency. They also provide incentives for distributed generation, and they do quite a bit of research and development projects, pilots, and those sorts of things for energy-related topics.

ConEdison also provides incentives for – through various residential and commercial demand response programs, and similarly on the energy efficiency side, the New York independent system operator, the transmission operator, also operates demand response programs in our territory. So customers have a – quite a few choices in terms of energy efficiency and demand response. On the energy efficiency side, there's – it's somewhat competing offerings. On the demand response side, it's actually complementary. So we're paying for demand response on the distribution side of things, and the ISO is paying for it on the bulk system side of things, so customers can actually take advantage of both.

Johanna Zetterberg: So Michael, actually a clarification came in from that questioner. How is the utility incented financially? So what mechanisms are in place to incentivize the utility, kind of?

Michael Harrington: There are financial incentives for achieving program goals.

Johanna Zetterberg: Can you talk a little bit more about that?

Michael Harrington: I can't – I'm the wrong person to talk about that. There's quite a bit of information about how this operates I'm sure online somewhere, but this is not my area of expertise.

Johanna Zetterberg: Okay. We can follow up offline on that. Just a couple of remaining questions in our few minutes left. This is a question for John. Within best practice IRPs, are customer costs included for demand resources when compared against supply resources?

John Shenot: That's a pretty good question. We did not address that specifically in the paper, but I think in the context of resource planning, the utility is going to be looking at its cost of acquiring resources, and not necessarily the total cost, including the customer's costs. I'd be happy to have someone correct me on that, if they know otherwise. But that's my understanding of it. They would just look at the utility's costs of acquiring those resources in the planning context. It would be different in an energy efficiency program planning context.

Johanna Zetterberg: Okay. Thanks. Another question for you, John. It's interesting to note that many of the examples used by the SEE Action Network and RAP in their paper show multi-state organizations. Is this due to utility territories, or to a planned effort by regulators to review a more holistic regional approach, or some other reason?

John Shenot: Well, you might recall that the last of the best practices listed on our list was – had to do with scale and regional planning, and I think that's part of the reason why we have that particular set of examples. There are plenty of utilities, like I mentioned Arizona public service, that work in one state and do a great job with integrated resource planning.

But given that – we, the working group saw that you can often identify economies if you're planning at a different scale than just looking at one utility. Utilities don't operate as islands. They're in an interconnected grid, and the least cost planning let's just say for Pacific Corp, their operation in six different states, if they look at it

across six states, they might find some economies that they wouldn't find if they did it, you know, specific plans, one state at a time.

Johanna Zetterberg: Thank you, John. Well, we are out of time today, and I want to sincerely thank our speakers for joining us today and sharing your presentations with us. As mentioned previously, these presentations will be available on the SEE Action website, and we'll let you know when those are available within the next two to three weeks.

So thanks again so much for joining us today. If you are not already signed up for the SEE Action listserv alerts, you can go to our home page, SEEACTION.Energy.gov, and sign up there. It's a very low traffic listserv, just two to three per month, and you'll be notified of upcoming webinars and new publications and other network events.

So this will conclude our webinar today. Thank you all. Goodbye.

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