STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

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Matter 15-00262 - In the Matter of a Three-Year Rate Proposal for Electric Rates and charges Submitted by the Long Island Power Authority & Service Provider, PSEG Long Island LLC.

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725 Veterans Memorial Highway
Smithtown, New York 11727

March 3, 2015
9:40 a.m.

ADMINISTRATIVE LAW JUDGES:

The Honorable DAVID R. VAN ORT

The Honorable MICHELLE L. PHILLIPS

EXPERT WITNESSES OF PSEG LONG ISLAND

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JOSEPH TRAINOR, Senior Manager in Regulation and Pricing of PSEG LI
GARY AHERN, Director of Finance of PSEG LI
NICK NAPOLI, VP of Power Markets of PSEG LI
MICHAEL VOLT, Director of Energy Efficiency and Renewables of PSEG LI
DANIEL EICHHORN, VP of Customer Service of PSEG LI
NICHOLAS LIZANICH, Director of T and D Asset Management of PSEG LI
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JUDGE PHILLIPS: I would like to call matter number 15-0262 in the matter of the three-year rate proposal for electric rates and charges submitted by the Long Island Power Authority and service provider PSEG, that's capital P-S-E-G, Long Island LLC. We are conducting a procedural conference that will be followed by a technical conference. This is on the record, and this is pursuant to a notice we issued on February 10, 2015, announcing this is the date and place of this procedure.

What I would like to start with is the taking of appearances just for the parties that are present. Just for ease, with respect to getting this down for the record, we'll start with the table in front of us. We have little cards that indicate that LIPA is sitting closest to us, and then we'll go to the first row of the auditorium, and again, we'll go around the semi-circle, please. So, starting with the LIPA card.

MR. BROCKS: Yes, your Honor, on behalf of the Long Island Power Authority, the Firm of Read and Laniado by Kevin Brocks, Howard Read, and Sam Laniado.

MR. KLIMBERG: On behalf of Caithness Energy, Stanley Klimberg, Firm of Ruskin, Moscou, and Faltischeck.

MR. WEISSMAN: On behalf of PSEG Long Island, your Honor, Matthew Weissman and Bruce Miller, Firm of Cullen and Dykman.

JUDGE PHILLIPS: The next row, first row of the auditorium.

MR. LAROE: Good afternoon, Independent Power Producers of New York. I am Christopher LaRoe.

JUDGE PHILLIPS: Is there anyone else who's sitting in the audience without a microphone who's representing a party? Okay.

Let's go to the semi-circle and start with Staff.

MR. MAZZA: Good morning, your Honor, on behalf of the Department of Public Staff, Guy Mazza and Nicholas Forst.

MR. GOODMAN: Good morning, your Honor, on behalf of New York City, Jay Goodman of Couch White, LLP, and I'm joined by Andrew Fiori (phonetic) who is with the Office of State, City of New York.

MS. HOGAN: On behalf of the Department of the State Utility Intervention Unit, I am Erin Hogan joined by Michael Zimmerman.

JUDGE PHILLIPS: Is there anyone else here that's representing a party who wishes to make an appearance? Okay. Thank you.

As we indicated in both, I believe the notice and the ruling of this matter, we had several things that we had on our agenda for the procedural conference.

Basically, we would like to start with the identification of parties, which we have pretty much done. We would like to maybe hear a little bit about the interests of the parties that are present. We will entertain any objections to requests for party status. That's the first step, then we want to discuss the schedule, and relating to that, any discovery issues that you may have, and then we'll turn to the scope of this matter.

Is there anything that anyone knows at this time that they would like to add to this agenda? Okay.

So, I don't know if LIPA, PSEG would like to say something quickly. I mean it's basically your filing. We kind of know you're seeking a rate request. Is there anything you would wish to add to your interest for the record?

MR. WEISSMAN: Not with respect to the procedural issues.

JUDGE PHILLIPS: Okay. So, I would like to next give IPPNY the opportunity to be heard.

MR. LAROE: IPPNY has already been monitoring and commenting on the Utility 2.0 Plan to date. We would like to see how the issues that arise in there, particularly as they relate to the utility ownership in relation with REV, demand energy resources, and the large scale utility renewables that are involved in this case.

JUDGE VAN ORT: Can the folks in the back hear this individual?

JUDGE PHILLIPS: We're actually going to switch the order a little bit. We would like to hear from UIU and identify your interest.

MS. HOGAN: Our interests are for the residential rates, and small commercial rates, and the increases that are being proposed.

JUDGE VAN ORT: Just note that Mr. Fogel came in. If you would take a card, and if you move up to one of these tables --

actually, move up to the front here, grace us with your presence, and give your card to the reporter.

JUDGE PHILLIPS: So, we'll continue with the City of New York, and can you identify the interests of your party?

MR. GOODMAN: Your Honor, the City of New York have two interests in this proceeding. The City, itself, has facilities where LIPA serves territory. The City also has interest representing in the capacity on behalf of its residents and businesses for customers of LIPA.

JUDGE PHILLIPS: We'll go to Caithness, I believe, the Caithness representative.

MR. KLIMBERG: Caithness is interested in the baseline power supplies that underlie the three-year rate plan, the costs that have been assumed in connection with those baseline power supplies, how those costs might be adjusted or revised in the event that there are changes in the supply plan over the three-year rate plan, and as well as the forecasts of load, and energy over the rate plan.

JUDGE PHILLIPS: Mr. Fogel, please, and if you could just please state the name of your party, and your interest proposal.

MR. FOGEL: Thank you, your Honor.

On behalf of the Retail Energy Supply Association, Usher Fogel.

The issues that are outlined in the plan of ours that we previously sent in is the Long Island Choice Program and the

Utility 2.0 Program that's been submitted by PSEG and LIPA previously.

JUDGE PHILLIPS: And I believe that leaves Department Staff.

MR. MAZZA: Thank you, your Honor.

In accordance with the LIPA Reform Act, LIPA and PSEG have provided a three-year rate plan to the Department for its review, and to ensure safe and adequate service, and reasonable rates for the customers of Long Island, DPS will be reviewing all aspects of the rate proceeding.

JUDGE PHILLIPS: I'm operating on the assumption that the parties have had an opportunity to look at the party list as it currently stands. You're aware at a minimum of those parties in the room who are seeking party status. Are there any objections to any requests that have been made for party status thus far?

MR. MILLER: Yes, your Honor, for PSEG Long Island, we have two areas of concern.

The first involves the energy service companies, the ESCOs, and the Long Island Choice Program. I think you've heard Mr. Fogel say that's what he's interested in. You might have seen two documents. You might not have seen the petition that RESA filed with LIPA. I believe it was in January asking for a forum, and then Staff filed their scoping statement in which DPS staff agreed that Long Island Choice issues should be on a separate track, and DPS staff offered to facilitate that track, in fact, to run it, I believe. It's a little bit -- I think we have to talk about the parameters of that, but they have offered that. It's PSEG Long Island, and I believe LIPA agrees that this is appropriate. We welcome Staff's offer.

I think given the very compressed time table we have in this case that if there is a better forum for the consideration of Long Island Choice issues, those issues ought to be heard in that forum. So, we would recommend the issues involving Long Island Choice be severed from this case, and be heard in the forum that the Staff is willing to facilitate and run.

JUDGE VAN ORT: Mr. Miller, can I ask, are you referring to, I believe the matter number is 14-01299, is that my understanding to what you're referring to? There's currently a pending matter before the Department of Public Service with respect to the LI Choice? That's a question.

MR. MILLER: I don't know that, your Honor.

JUDGE VAN ORT: Mr. Mazza.

MR. MAZZA: I'm sorry, your Honor, I'm not familiar with that.

JUDGE VAN ORT: You're not familiar, okay. Thank you.

JUDGE PHILLIPS: I just have a clarification, are you objecting to the individuals who identified LI Choice as issues that they are concerned in having party status, or are you just objecting to that issue of Long Island Choice being included as part of this matter?

MR. MILLER: I think we can do it either way, your Honor, I don't think there's any magic to it. It's clear to me that the energy service companies are interested in Long Island Choice. If that issue was removed from the case, I suppose they might have other issues in the case. They don't necessarily need to be removed from the case or denied party status, but I don't know if they would have further interest in what we're doing here.

I also noticed that -- I believe it was Mr. Fogel who also referred to Utility 2.0, and that was also on a separate track in a proceeding that DPS Staff is also facilitating, so those issues are really not appropriate for this case. There's not really any 2.0 in this case.

JUDGE PHILLIPS: Mr. Fogel?

MR. FOGEL: First of all, I would disagree about providing party status. I think our interest under the Public Service Law are clear, and there's no reason to deny us public status. I think it would be contrary to our forty-five years of history, so I don't think we want to start a proceeding on that note.

In terms of the proposal for Staff -- well, let me take a step back. The company in its file testimony, if my recollection is correct, with respect to Long Island Choice Program had recommended that it collaboratively established. I believe Staff in their scoping comments that came in, and said that given the importance of the issue, they felt it would be better handled either as a separate proceeding, I believe that was the language they used, not necessarily as a separate phase. We don't necessarily have -- speaking on behalf of the RESA, we do not necessarily have a problem with taking that procedural approach. However, before I agree to severance, I want to have a specific time table and schedule put in place, so I know this is going to be addressed, hopefully, before my grandchildren get married. So, with that caveat, I think maybe we can have some discussions and negotiations about that, but until such time something specific is on the table with set dates, schedule, etcetera, then I would maintain, it should be continued as part of this proceeding because the Company did raise it in their filing. So, that's really where our position is.

I recognize that some were preliminary because these proposals first came on the table in the scoping comments, but we're willing to talk about it, but until that time happens, we're in here.

MR. MILLER: Your Honor, I don't necessarily disagree with what Mr. Fogel said, you know, right now we have an offer to your Honors from parties in DPS. If that offer were to be accepted, if the Department were to accept Staff's offer, and go down that track, I think down that track in that process, we could get scheduling going forward, and you could hold the motion in conveyance until we reach that point.

JUDGE PHILLIPS: We were just discussing your motion, and I think with respect to the extent to which it was a motion that we deny party status to RESA or other energy service companies, we don't think that it's necessary to grant that motion. We would not deny them party status because they've raised issues that may properly belong to other parties or not. I don't know that, that determination has been made, but I don't think it establishes sufficient basis for denying them party status.

What it does possibly go to though, is the scope of issues, which is another thing that we're going to discuss here today. So, based on what you've argued, we are denying the request not to grant them party status, and they'll remain in the case for now. I don't know if there are any other objections to the request for party status at this point.

MR. MILLER: There is, your Honor, and this will not be dissimilar from the ESCO motion.

Caithness Energies asked for party status. Caithness has made the point that there is a power supply plan that underlies our case. The power supply plan that underlies our case is that there's no generation needed during the term of the rate plan, which is from 2016 to 2018. That's a matter that was presented to the LIPA Board. LIPA Board did not object. So, our case was filed without any new generation resources.

Our case also says in our power supply testimony that there will be an integrated resource plan developed in 2015. That plan will then be presented to LIPA and LIPA will have a process at which intervention will occur and parties will have a chance to make their case to the LIPA Board based on the recommendations that PSEG Long Island makes after the conclusion of the integrated resource plan, but as of now, there is no generation. Caithness is looking to build a 700-odd megawatt facility. They have a commercial interest, and I don't think that this case is the appropriate place to pursue that commercial interest.

JUDGE PHILLIPS: Again, does your objection go to the issue that they raised, or to them having party status at all?

MR. MILLER: Your Honor, I don't want to push the removal of parties from the case, but I do think if we take out issues, and find that they're inappropriate for the case, that accomplishes the purpose of what I would like to pursue.

MR. KLIMBERG: Caithness would like to respond.

JUDGE PHILLIPS: Yes, I was going to give you the opportunity to respond. If you would please speak through the microphone.

MR. KLIMBERG: PSEG Long Island has submitted testimony, a power supply POW that lays out their assumptions regarding their baseline power supply plan, and based on that, a three-year rate plan. If there are changes in that assumption, then there are obviously cost implications to the ratepayers from changes in their baseline power supply plan. It's correct that PSEG Long Island has underway an integrated resource plan, but results of that plan, which are being conducted outside this rate proceeding may well have significant effects of the rates over a three-year period.

Mr. Miller states that the assumption that there is no generation needed, but that hasn't been tested, and indeed, if there are changes that arise as a result of the integrated resource plan, then there will have to be adjustments in the rates. I think it's fair to explore that issue in this rate proceeding.

They have also proposed a delivery adjustment, which will automatically adjust the rates based upon changes in their power supply plan. The reasonableness of that delivery service adjustment is a proper subject to this rate proceeding.

MR. MILLER: If I may be heard, your Honor, the facts are in this case that there's not something lurking in the rate plan that the IRP will somehow reveal. The presentation that was made to the LIPA Board, I believe last summer, showed that no new resources will be needed until 2022, that has been pushed out further to 2024. What that integrated resource plan will do will affect the future, it won't affect anything in this case, that's why this case doesn't have any new generation resources in it. That's what was presented to the LIPA Board.

What may be needed in the future after the expiration of the rate plan, which will be determined as part of the IRP process will be for the future beyond the termination of this rate plan following the expiration of 2018. That's why there is no generation here. Because of that, we were able to avoid spending several billions of dollars that otherwise would have been spent. So, the plan itself assumes no generation, that was presented to the LIPA Board. The LIPA Board is responsible for this. The LIPA Board will have a process down the road when the IRP is finished for parties to weigh in at public forums.

MR. KLIMBERG: What Mr. Miller has stated is not correct. The LIPA Board has not approved the proposal that PSEG Long Island has made in connection with its resource planning recommendations. PSEG Long Island has made those recommendations, it has submitted reports, and it has made assumptions in the rate case regarding Long Island's need for future resources. The board has made no decision with respect to the recommendations that have been made. It's clear that there are assumptions that have been made in the rate plan regarding the need for additional resources. PSEG Long Island has said that there is no need during the three-year rate plan, but it has noted that there is an IRP, integrated resource planning process, under way, which will look into what the future needs are, and it may well arise as a result of that proceeding, that it will be determined that there is a need for additional resources, which will require the costs be incurred during the three-year rate period that will need to be reflected in the rates, and indeed PSEG Long Island has proposed a delivery service adjustment mechanism that will allow for the reflection of those additional costs.

Further, there is authority under an amended and restated power supply agreement that Long Island Power Authority has with National Grid generation, which allows for the ramp down of generation under that contract. The costs associated with the non-fuel portion of those contact arrangements are reflected in the delivery rates, so if, as LIPA is authorized to do, there is a ramp down of facilities during the three-year rate plan, then there will be costs that will need to be addressed through rates, or through a delivery service mechanism, or outside this process. So, as a result, we believe that this is an appropriate area for examination in the rate plan.

JUDGE PHILLIPS: Can I just ask a clarifying question though, do you concur or not with what I thought I heard, that there is a separate proceeding with respect to determining this issue of generation need, the IRP proceeding?

MR. KLIMBERG: There is an integrated resource plan in process that PSEG has initiated. It has scheduled, or projected that it will be completed by the end of this year.

JUDGE PHILLIPS: Let me stop you, like December of this year?

MR. KLIMBERG: In December.

PSEG Long Island has established this process. The nature of the process is quite different than this rate proceeding.

According to PSEG Long Island, there will be informational meetings, and they will obtain input from the public relating to the development of that plan. What comes of that plan may well be a determination that there is a need for additional generation in this decade, which will require the cost to be incurred in order to support that additional generation.

What PSEG Long Island has stated in this rate plan is that any costs that might be incurred in the nature of it, that will be reflected in the delivery rates, will be reflected through the delivery service adjustments. If they are not costs that would be reflected in delivery service that would not be delivery rated, then these are costs that would be outside that mechanism, and it's not clear how those costs would be recovered from rate payers. So, through that IRP process, which is being conducted parallel to this rate case, that could well be costs that are incurred, and we're interested in knowing how that is going to be done, what is the relationship between the integrated resource planning process and this rate case.

JUDGE PHILLIPS: Another clarifying question, just to test your understanding to see whether or not it is the same, the LIPA Board though, is responsible for approving or disapproving your IRP plan, is that your understanding?

MR. KLIMBERG: I'm not sure how the LIPA Board will address the integrated resource plan. LIPA is ultimately responsible for decisions regarding generation. PSEG Long Island has a responsibility for making the recommendations and performing analyses in connection to rate planning. It is my understanding that LIPA Board is openly responsible for making those decisions, but has not made any decision yet with respect to future generation.

JUDGE PHILLIPS: One more question before I turn to Mr. Miller, is it your understanding that you can intervene as a party as part of that process?

MR. KLIMBERG: Clearly, it would be better directed to PSEG Long Island as to what that integrated resource plan will be. We have only seen some limited information on how that will be conducted, but it would not be as a formal process such as being conducted here today in the rate case.

JUDGE PHILLIPS: Mr. Miller?

MR. MILLER: I had discussions with LIPA yesterday on just that topic. Mr. Klimberg is -- he's correct in that the process that happened, that was last summer, PSEG did an analysis of the need for power based on the NYISO criteria, and concluded there was not a need at that time until 2022, that was subsequently pushed out to 2024.

There is an integrated resource plan that is being pursued now that will be done at the end of this year. LIPA's procedures will be -- what will happen is, PSEG as a result of that integrated resource plan, will make recommendations to LIPA as to resources that will be needed in the future beyond this rate plan period. LIPA will then have a public process to investigate PSEG's recommendations. So, any idea that we know will eventuate from that integrated resource plan, which won't even be done until this case is almost complete, is speculation. What we do know is there is no new generation resources needed during the period of this rate plan, and as to what might happen, and how that might be effectuated beyond this rate plan just does not affect the period of this rate plan. Anything we would do would be speculative as to what might come out of that integrated resource planning process, which will only begin when the recommendations are made by PSEG Long Island to LIPA Board at the end of 2018.

JUDGE VAN ORT: Let me ask you a question, am I understanding you correctly that there would be no impact, that there would be no possibility of impact from the IRP for the three years 2016 to 2018?

MR. MILLER: That is my understanding because there is no generation needed into the next decade, 2024, now within the NYISO planning criteria.

MR. KLIMBERG: Mr. Miller is making a conclusion based on an analysis performed by PSEG Long Island, which assumes that all of the generation that's currently operating on Long Island will continue to operate, and based on its analysis, and assumptions, based on its criteria for determining need.

LIPA, as I mentioned, has a right to ramp down much of the current National Grid generation under contract to LIPA in operation prior to 1998. If any of that generation were to be ramped down, in other words, retire, potentially, then that would not be available, so the calculation of need would change as a result of that decision. So, LIPA has the authority now to ramp down generation, which would change the need picture during this 2016 to 2018 rate plan period.

In addition, in the testimony, PSEG has assumed that all of the generation under contract to LIPA that is expiring during the rate plan period will continue to operate even if the contracts, the expiring contracts, were not extended. That's an assumption and hasn't been tested, so what I'm suggesting is that when Mr. Miller, on behalf of PSEG Long Island, states there is no need based upon their analysis, that is based on their assumption that all of this generation will continue to operate as it is now, and I don't think that we can simply assume that for purposes of this rate plan.

JUDGE PHILLIPS: We have conferred briefly, and again, we believe that we tend to err on the side of more inclusion with respect to party status. We recognize the issues that have been articulated by Caithness dated February 25th, I believe, in response to our request for identification of scope of issues that they are interested in, may or may not be issues that are addressed in this case. They may be resolved as a separate RFP, there may or may not be changes made in the generation plans.

We don't know that at this point, but our inclination right now is to allow Caithness to remain as a party, but recognizing the issues you articulated in your letter about which you expressed interest today, may or may not end up being a part of the scope of this case.

Our decision to allow you to remain in as a party is not reflective of anything with respect to the scope of issues that we have not fully addressed in this proceeding yet or is part of this conference.

Are there any other party status issues or parties that we need to address? Thank you.

JUDGE VAN ORT: Are any of the other parties having any objections to other parties or prospective parties remaining?

MR. FOGEL: No, your Honor.

MR. MAZZA: No, your Honor.

MR. GOODMAN: No, your Honor.

MS. HOGAN: No, your Honor.

MR. LAROE: No, your Honor.

JUDGE VAN ORT: Thank you.

JUDGE PHILLIPS: Thank you.

So, one of the second of two issues that we identified as part of our agenda in our ruling that was issued February 3rd, we proposed a schedule for intervener and staff testimony, rebuttal testimony, and evidentiary hearing dates. The staff intervener testimony date that we proposed was April 30th, rebuttal testimony proposed for May 13th, evidentiary hearing proposed for May 27th, but we said that we would be willing to hear arguments or concerns as to why this schedule should not be adopted, so we would like to open that up now for the parties to address that as they wish.

MR. MAZZA: Your Honor, this is Guy Mazza for Staff.

I would like to address the schedule if I may. As you've indicated, the date was established April 30th for the staff and intervener testimony. There are two significant reasons for which we would like to request that that date be extended by two weeks.

First of all, LIPA and PSEG are two companies with which staff have not had extensive experience until this point in this rate case context. That being the case, it is taking more time than it would normally be expected of an investor-owned utility in which the department had extensive experience in the past to undertake and to review. We feel that two more weeks is necessary for that to occur effectively.

Secondly, the rate model, which is filed by the Authority and the Company is one with which Staff has not had extensive experience, and this requires, again, a higher level of review than it would be as ordinarily in this case. For those two reasons, we would request that that be extended by two weeks.

In view of the possibility of a concern with respect to the timeframe within which the Judges and the Department have to fulfill its responsibilities after the hearing and the briefing, Staff will propose that the brief proposing sections, which may well be anticipated in this proceeding, be eliminated or timeframe produced, that's normally two to three weeks provided for that, and Staff feels that there be on exceptions is important, but the briefing proposal exceptions could well be utilized to make up unnecessary time. Thank you.

JUDGE PHILLIPS: I just want to clarify, the two weeks that you proposed though, it would carry through to the other dates as well, so would each of those dates be extended be two weeks as well?

MR. MAZZA: That would be our expectation.

JUDGE VAN ORT: I guess this is more of a theoretical question, but what assurance do we have that if we shift this by two weeks, being the difficulties we have experienced, that we're not going to be in the same situation two weeks down the road. I hate to use the term "kicking the can down the road," but sometimes we get into that circumstance, and I don't want that to happen here.

MR. MILLER: Your Honor, can we be heard on this?

A couple of points, I think there's roughly an eight month schedule under the LIPA Reform Act, so we've scheduled accounts for about four months for that, the other four months are not identified here, so we really don't know what we're working with, and how much time we're working with.

What Mr. Mazza is saying here about Staff's difficulties is absolutely correct. I think we have to recognize that they haven't had experience with LIPA and PSEG before, and we're dealing with a new model, rate making model, in which Staff is not familiar. We've probably met with DPS staff seven, eight, nine times to try to help them familiarize themselves.

All of the parties are doing the best they can, but I take what Mr. Mazza is saying seriously. We're all struggling with this requirement that was imposed by the LIPA Reform Act. I think Mr. Mazza's suggestion that we dispense with one of the briefs on exceptions is probably one way that we can buy another two or three weeks. I think we would go along with that. Although, we don't know what those exceptions are being proposed and to whom those exceptions would be made. We think we might guess as to the recommendation decision process not being the last word on this, but we just don't know, maybe, your Honors, could fill us in on the process we are looking at.

We also think two weeks for rebuttal is extremely short. It's usually more than three in a DPS case, and we would be looking for a little bit more time there too.

JUDGE PHILLIPS: I'm sorry, when you're saying you're looking for a little bit more time, are you looking for more than two weeks?

MR. MILLER: Yes.

JUDGE PHILLIPS: Do you have concrete dates then that you're prepared to give us on this proposal that you're making?

MR. MILLER: I think if we move the Staff testimony out two weeks -- do you have a date for that?

MR. MAZZA: That would be May 14th.

MR. MILLER: May 14th, okay. I would just like to check the dates.

MR. GOODMAN: While Mr. Miller is checking, the City of New York would like to be heard on this issue.

JUDGE PHILLIPS: Yes, I just wanted to get the dates, and then I wanted to ask if this was a consensus proposal, and if other parties had any concerns they wanted to address.

MR. MILLER: May 14th looks like a Thursday.

JUDGE PHILLIPS: What would be the proposed date for rebuttal testimony date under your offer?

MR. MILLER: It looks like June 4th.

JUDGE PHILLIPS: And then evidentiary hearing date, commencement date?

MR. MILLER: We have been talking about June 23rd, your Honor, June 4th, the Thursday for rebuttal, does that make sense to Staff?

MR. MAZZA: Yes, it does.

JUDGE PHILLIPS: I would like to hear from other parties. Is this a consensus proposal, are there any concerns that any of the other parties have about this proposal? We'll start with New York, and then kind of just move down the line.

MR. GOODMAN: Thank you, your Honor.

New York City fully supports Staff's and PSEG's request for an extension to our timely schedule.

We also note that discovery is an iterative process, often the first round of discovery is needed to get the information needed to get that subsequent sector or more rounds, including detailed information. The response to which really is essential for the development for complete testimony. So, the City also believes that a modest extension of testimony will be very useful to further develop the testimony already submitted. New York City has no objections for the proposed extensions here for the two weeks for the submission Staff intervener testimony and the initial dates that were suggested by Mr. Miller.

The City has no comment about Mr. Mazza's recommendation regarding RESA. The City prefers that, all else equal, there is an opportunity for opposing exceptions, if those additional rounds of briefing are going to be included to the extent that scheduling is concerned as Mr. Mazza noted about the time provided between the 5/03 spot exceptions and the opposing exceptions can be shortened. The City would also be willing to accept page limit on the final briefing of those exceptions.

With that said, the City, I believe it has a preference for additional time at the forefront end for the proceeding here, and will be willing to forego the three proposing exceptions if that is what is necessary to secure the issue time on these deadlines that we're discussing.

JUDGE PHILLIPS: UIU?

MS. HOGAN: UIU certainly does not have an objection to the two-week extension here for testimony, rebuttal, and the evidentiary hearings. I'm just reluctant at this point to put in a position on whether or not there should be dispensing with one of the briefs to the exceptions, so I think I'm going to refer to your Honors to the determination if that is appropriate.

JUDGE PHILLIPS: IPPNY?

MR. LAROE: I think we're on the same page as UIU, no objections with the schedule being on time.

JUDGE PHILLIPS: RESA?

MR. FOGEL: Yes, your Honor, we have no objections to the proposed revisions of the schedule.

MR. MAZZA: Your Honor, if I may reiterate. I wouldn't have an objection to if, your Honor, your judgment, if it was more appropriate to modify the times to the proposed exceptions rather than eliminate them.

JUDGE PHILLIPS: We note that in stating its position of New York City to other than its discovery, are there any other issues with respect to discovery that might impact or sway us with respect to this request of an extension that any party wishes to raise?

MR. GOODMAN: Your Honor, the City currently has no concern or dispute with respect to the schedule. It appears that PSEG and the Authority have been diligent in terms of response to -- there's a large volume of fairly detailed information on a timely basis, however, on the condensed schedule that we're operating here, the typical timeframe for discovery response under the Commission's relations is ten days. The parties have asked for expedited scheduling, whatever that timing is, whether it's five, or ten days, or longer, a reasonable amount of time, again it's a standard of the process that you usually need follow-up questions after discovery issues. So, it wouldn't be uncommon for me for a month at least to get the base information before testimony. So, even in the absence of the dispute of discovery, just the timing it takes for questions or responses, analyzing all possible information to get the questions out, it's extremely helpful to have additional time in advance of testimony to get through that process, getting that efficient.

MR. MAZZA: Your Honor, there is one more discovery issue that I was expecting to bring up later.

The Commission's regulations call for ten days for discovery. We have at the beginning of this process requested five days, and in view of the need to develop its recommendations or conduct this review in the timeframe to provide the opportunity for Staff to develop its recommendations, I would request it would be five days rather than ten days.

JUDGE PHILLIPS: Do the applicants want to be heard on that?

MR. MILLER: Yes.

We're doing the best we can, your Honor, but five days is just not possible. I think what we would end up with is a process where we would take up more time in our inability to answer in five days, and either asking for more time in trying to resolve objections, now, we'll be withdrawing objections, and trying to give some answers.

Again, I think a lot of this is a result of how different this case is from any other case that has been heard before the Department of Public Service Commission. The model is completely different. Five days, I think, you know, from your time in the normal PSEG rate cases that ten days often is not met, and in this regard, there's really no difference. If you rule five days, we'll be making more explanations of why we can't do it in five days, and that would be counterproductive. We're doing it as quickly as we can.

JUDGE VAN ORT: One of the things that concerns me about this, as we know being involved in rate cases in the past, as time goes on, the discovery numbers increase and tends to pick up speed. It's like a rolling ball. If we're having difficulties at this point in time, it's my concern that it's only going to get worse if something doesn't take place to get it to smooth out.

I think one of the things that will be helpful, and I have spoken to the Judge about this, is to have the parties indicate to us where they are in the context of discovery, how many questions they have asked, you know, what percentage they think they may have completed at this point. I think this gives us a consensus when we evaluate this as to whether we have a level of comfort. Our concern is that you barely cracked the book open and we have a long ways to go.

MR. MAZZA: Might I suggest a request, your Honor, that that be conducted by way of dedicated conference call for that issue, sooner rather than later, of course, but perhaps this week?

JUDGE PHILLIPS: Yes, we are definitely open to that, but I think in the meantime I would strongly encourage all of the parties to talk to each other, and maybe try to explore other ways to conduct discovery. Anything that can expedite this process would be helpful because you guys are not the only ones who are under a time press here. We all have to comply with the requirements of the Reform Act, and we all have less time than we would otherwise have for a regular rate case not under the LIPA Reform Act. So, we're all subject to a shorter period of time. So, to the extent we can find ways to expeditiously conduct discovery, expeditiously move along, I think that would help everyone, and would help everyone on both sides of the issue.

So, we strongly encourage that and we'll hope that you'll think about that, and we'll try to schedule a conference call as soon as possible with all of the parties to touch base with you as to what ideas you've come up with to try to facilitate that goal.

MR. MILLER: Your Honor, if I may be heard, I agree with you. This technical conference will also be helpful with that, but I think -- we have already met with DPS informally for hours, February 5, February 10, February 12, February 17, so we have had ongoing attempts to use an alternative method to bringing the parties together, help DPS understand what's in the case, where it is, get them additional information, we'll continue to do that.

It's the informal interrogatory process, especially a five day process, that is just not going to work, and as I said, we're committed to getting answers as quickly as possible, and use these alternative methods. Every time that someone suggests that a meeting is appropriate, we round up our technical people, and we meet, and we'll continue to do that.

JUDGE VAN ORT: Can I just ask a clarifying question, you're not engaging in simply formal discovery, correct?

MR. MILLER: Correct.

MR. MAZZA: That is correct, your Honor.

MR. GOODMAN: I would like to say something, your Honor, if I may?

JUDGE VAN ORT: Go ahead.

MR. GOODMAN: First, we hear the concerns about potentially kicking the can down the road here, and we acknowledge that, yes, this is a compressed timeframe, and the pace and scope of discovery by all parties may increase, and the challenge is just going to get greater. With that said, I think there is recognition that additional time in the front-end would be useful, and we also recognize that we're working within a time constraint, and have to live within that. If the extension that was discussed was granted, I can only speak for the City, but we would assume that's the end of it. So, at that point, so to speak, we wouldn't ask for another week here, and another week there.

To the suggestion that we explore alternative methods of discovery, the City is certainly open to it. I know we have just heard, and it's typical for a rate case that utility and Staff are having very informal discussions, to the extent of that process, it would actually be increased here to facilitate discovery. We have some slight concern potentially about understanding what information that's being developed in those informal discussions that haven't been reflected in discovery. It's really just noting concern.

We're also suggesting that all informal discovery should be summarized or otherwise reported. However, at a minimum, I think we would strongly encourage the company and Staff, instead if they were willing to rely on information obtained in those meetings, that's either filed in formal discovery, so that all parties can see what the response is, or detailed in testimony. As long as it's produced by one of those two methods, it at least provides an opportunity to understand what information was exchanged.

JUDGE PHILLIPS: Right, to clarify, I believe this is what normally does happen, and it was my expectation that was going to happen here as well.

So, I guess just echoing or following up on the concern that was raised by Judge Van Ort, as far as getting it to a volume of questions that are focussed on what the parties want for their testimony purposes, and want to present, I think it would be, perhaps, helpful to continue the informal discussions because a lot of times, you know, just going back to when we both worked as Staff Counsels, if you sit down and talked to someone first, you can actually get to the question you really want to ask, and get to the information you really want, quicker than asking a question, having the person come back and either say they don't understand and they give you something that is not really what you wanted. Sometimes just having that face-to-face dialogue helps you get to that point a lot quicker instead of going through, you know, asking a question, waiting ten days, it's not the right answer, you ask another question because we don't have the luxury of time here.

So, that's all we wanted, and we hoped that it would be inclusive of all of the parties who think they would want to file testimony in this case to sit down and talk to one another to try to resolve those misunderstandings or potential misunderstandings right up front, and then you can memorialize what you really want in terms of discovery in more formal fashion, whether that's in your testimony, whether it's in a formal IR, or other formal document. We leave that to the parties to determine, but we are very much open to, and encouraging of any methods that you can use to help facilitate the ultimate goal here of getting testimony that is informed, that is accurate, and that contributes to the record, so, that we can all comply with the obligations that we have under the LIPA Reform Act.

MR. MAZZA: Your Honors, if I may, we have been, as Mr. Miller indicated, we frequent with LIPA and PSEG, and to New York City's concerns, we do follow up with formal IRs that were appropriate, and I would also like to address Judge Van Ort's concern with kicking the can down the road, and try to assure him to the best of our ability -- expectation, that would not be the case here because as understandings are developed of the company, and the new model, it facilitates a more rapid understanding going forward, and I don't see this as anything as kicking the can down the road.

JUDGE PHILLIPS: Absent any other clarifying questions or opportunities to be heard on this issue, what we would like to indicate is we'll take this under advisement, and we plan to issue a ruling on it as quickly as possible.

With that, I guess we would like to move to scope of issues. We also indicated that there would be an opportunity in the procedural conference to discuss that a little further. With respect to party status, I can already guess that we have some desire to be heard by different people as to their concerns about proposed scope of issues.

MR. MAZZA: Yes, your Honors, if I may speak. In our scoping document that we've submitted on February 13th in response to your Honors' request, we have four different areas that we would look to see the scope expanded to, and I'll just address that briefly, or more at length if necessary.

The first was respect to retail access. As we have discussed earlier today, the company proposed that this be handled in this proceeding as a collaborative. Staff made a proposal that this be instead handled as a more formalized review that would be undertaken by Staff involving the parties as appropriate in a more formalized process going forward. We don't have a specific timeframe at this point, but we certainly don't expect it to involve Mr. Fogel's grandchildren, and that's something we would undertake as expeditiously as soon as possible in the context of our other responsibilities of the rate case, etcetera.

We had spoken about load pocket mitigations, discussed what is in company and the Authority, and we have some assurances that that is not necessary to ingest in any more detail at this point.

JUDGE PHILLIPS: Wait, clarification in that, I believe in your document you said, I thought you were proposing the strategies for 2.0, are you now withdrawing that suggestion?

MR. MAZZA: Well, we have never suggested, your Honor, that 2.0 be included in this rate proceeding.

What we're concerned about is that load pockets be addressed either in conventional infrastructure improvement, or with the expectation of Utility 2.0, but we saw that there were various areas that was important to address, and it's been explained to us that they have been addressed in the proceeding, not with respect to 2.0 at this point, but we do have an expectation and the hope that as that develops, those solutions be implemented. However, we're not proposing that will be included in the rate case at this point.

JUDGE PHILLIPS: So, let me try to rephrase again, are you saying then you agree that nothing relating to 2.0 should be in this rate matter addressed here?

MR. MAZZA: It's important that this be an expectation that this be a viable method going forward of addressing the needs on Long Island, but 2.0 is being evaluated in a separate review. So, I'm not saying necessarily that the rate case be conducted in a vacuum with respect to 2.0, but that to the extent that the 2.0 solutions have not been, perhaps, developed at this point, that they be looked into the future to be implemented as solutions to Long Island.

JUDGE PHILLIPS: But as part of the Utility 2.0 proceeding?

MR. MAZZA: Yes, Utility 2.0 subsequent to review.

JUDGE PHILLIPS: Thank you.

JUDGE VAN ORT: Mr. Mazza, can I ask you a question about that because that's one of the issues that's confusing for me? You have the Utility 2.0 docket, and I assume at some point that some determinations will be made in that case, and various options will be put on the table, and again further, soon there will be a revenue impact associated with those, the question that came to my mind in a normal rate making process, the rate case in many times will be near the rate impact side that will be addressed, how they'll be recovered, and in what manner, is that what we envision here because then it would seem to me even if Utility 2.0 goes on its way in that separate docket, if there are revenue implications from damage, I'm assuming there will be, if it's not here, where will it be handled?

MR. MILLER: It would be handled in the Utility 2.0 docket because in the Utility 2.0 docket, you would be looking at each program, the merits of the program, the cost benefits of the program, and how the cost related to that program should be covered. We don't know what the LIPA Board will determine in that process, and there are mechanisms already in place that can be used. For example, the energy efficiency clause that LIPA already has that we can use.

We just don't know, and we don't want to presuppose how LIPA would want to finance some of these Utility 2.0 projects. We don't even know the ones, if they're going to be approved, so, the case we filed doesn't have it in it. The case solves for conventional solutions in the absence of the 2.0 solutions that, frankly, are preferred.

JUDGE PHILLIPS: So, are you saying that LIPA in the context that it's LIPA's authority, once it determines which projects it wants to approve, will then choose how that recovery is going to be done, regardless of what happens in the rate case in which we will be setting rates?

MR. MILLER: I believe that's the way it's going to come out, and I think those projects will be approved, sort of series as they come up.

MR. LAROE: I'm not sure if it's accurate to say regardless of what happens with the rate case, it's consistent with what happens in this rate case.

MR. FOGEL: I guess I don't know how that really happens unless some provision is made. For example, let's say we come up with some sort of rate design, how we want rates to be started for a variety of reasons. It seems to be potentially, subsequently, a recovery, which would be significant to have an impact on how that rate design is constructed, so I don't know necessarily how you thoroughly defuse one issue out of the other, or create this very bright line, and it sort of has been like an issue that it seemed to me like it fluttered a lot about a lot of other issues between this context of this rate case because it is different from its other commission proceedings, and I don't know how you make that separate line all the time.

JUDGE VAN ORT: Mr. Mazza, before you speak, could someone tell me what the status of that is, is there ongoing meetings or anything with respect to the Utility 2.0?

MR. MAZZA: There are, your Honor, the Department has been meeting, working with the governing party on 2.0.

JUDGE VAN ORT: Can you tell us when this is expected to conclude? I don't want to hear from Mr. Fogel again indicating about his grandchildren.

MR. MAZZA: Your Honor, it's expected to be concluded probably within the next two weeks.

If I may add something myself, I want to dissuade anybody of the opinion that 2.0 is something separate out there. Utility 2.0 is a method for meeting the electric needs of customers. Those needs are currently being met with respect to customers by conventional infrastructure, so the money for that is in this rate case right now to the extent that that's modified going forward to utilize Utility 2.0 or other REV like solutions. It's not a separate set of money. It's funds that are already in the rate case being used in a different way, but is expected to be used as 2.0 and REV developed. There is actually -- I advise there's some Utility 2.0 capital funding in the rate case right now.

MR. LANIADO: Your Honors, I'm not sure that is correct that there's Utility 2.0 funding in the rate case, but I also think that some of the issues are prepared in the technical conference of this proceeding today to address issues regarding the place of Utility 2.0 in the case, and we have our technical experts here to discuss that in that portion of the technical proceeding.

JUDGE PHILLIPS: So, I think we have heard from Staff on these issues, do you want to continue with respect to your scoping issues?

MR. MAZZA: Yes, your Honor, just two more points.

There's a revenue decoupling mechanism that has been proposed by Company, and the Authority, this, however, is not specifically included in the rate case. The usual process for a commission implemented revenue decoupling mechanism with respect to an investor-owned utility, is that it be done in the context of a rate case, so that the specific deciding details can be evaluated by the parties, and that being the case for the rates after January 1, 2016, we would like to see the RDM included in the rate case.

Lastly, in 2014, the Company and Authority proposed a tariff amendment. The Department at that point issued a positive recommendation on that tariff amendment with the expectation that, although it did meet the intent of the LIPA Reform Act, we would review it more thoroughly in the context of the rate case, and in the delivery rate modification, we would just like to ensure that that's going to be included in the right proceeding.

JUDGE VAN ORT: Let me just ask for clarification, are you referring to tariff amendment regarding RDM?

MR. MAZZA: No, this is something different. This is a tariff amendment that's proposed in a number of respects in 2014. Although we made positive recommendations because it did comport with the LIPA Reform Act, we did indicate to that recommendation that we consider it more formally in the rate proceeding.

MR. MILLER: Your Honor, LIPA will be considering a RDM for implementation in April under its set in rate-making authority. DPS is concerned that, somehow that would stop them from addressing the RDM in the rate case. We proposed the RDM in the rate case, and there is no effort on our part to say that Staff would be stopped from discussing that subject along with any other rate design or proposal in the case.

JUDGE VAN ORT: Thank you.

JUDGE PHILLIPS: So, I know that several other parties, RESA, New York City, and Caithness also submitted a proposed scope of issues. I think we have already discussed the issues that are set forth by Caithness. We have discussed LI Choice Utility 2.0 as set fourth by RESA. New York City, however, had some additional issues that it had identified, mainly the storm hardening and resiliency. Does Company have objection to that being within the scope of issues, or do other parties have any objection to that being within the scope of issues here?

MR. LANIADO: Again, your Honor, we have included -- we do have testimony in the case regarding our storm response. I know New York City requested we discuss, I believe at this technical conference, the storm hardening efforts that are underway, and we prepared those in the technical conference today. We don't believe there are significant issues that refers to the rate case itself, but we have no objection to answering questions in our presentation regarding what we're doing with that in this case at this technical conference.

JUDGE PHILLIPS: I believe, and I don't want to cut anyone off, so correct me if I'm wrong, but I think we've pretty much touched on the scope of issues that were identified by parties that have provided us with such a list. If anyone feels that they haven't been heard, please speak now.

MR. GOODMAN: Your Honor, the New York City would like to be heard for a moment.

JUDGE PHILLIPS: Okay.

MR. GOODMAN: Thank you.

As noted, we would like to see storm hardening included in the scope of issues. It sounds like there's no objections to that.

Some of the other issues that interest the City, I think calls for rate filing notes that need to be detailed, for instance, revenue requirements is not assumed to be discussed.

We do have further comment on Utility 2.0. The City of New York believes that is something that should be included within the scope issues of the rate review.

With that said, as we heard this morning that the Utility 2.0 Plan may be completed within approximately two weeks. I'm not sure if that means that that's when it would be adopted and formalized, or if there is some earlier procedural milestone that will occur in two weeks.

However, we note that specifically what is in the current plan that may be approved within two weeks or so, it appears the Utility 2.0 can generally have an impact on operations, certainly on costs. Those issues are, I think should be going into this rate review, which is all the cost elements of the company and their capital investment program. It would, as Mr. Mazza said, would not make sense, and I don't mean to put words in your mouth, but I don't think it would make sense to have the rate review proceeding in a vacuum without understanding cost expenditures, capital investment plans, that may be modified potentially significantly by the 2.0 Plan.

We do believe that the 2.0 Plan are in some respects in the rate filing. My understanding is that the 2015 operating budget does reflect tens of millions of dollars on the 2.0 related project. We assume that that amount will continue, if not increase, potentially materially in the future. We share Mr. Fogel's concern without understanding those costs during the time of what the rate plan might be, that we're at risk of considering a rate increase that's significantly understated what customers may actually realize in 2015. The 2.0 Plan issues are not considered in depth here and are not completed.

JUDGE PHILLIPS: Thank you.

Does anyone else want to be heard with regard to scope of issues?

MR. MAZZA: If I could address that for one moment. I think in my view, there may have been a bit of a misunderstanding to expect that 2.0 is going to increase costs, rather it's expected to have a beneficial effect by relieving the need for more conditional infrastructure needs that are necessary for a reliable system.

MR. GOODMAN: I appreciate the clarification. If the Company wanted to stipulate the 2.0 review to reduce costs without incurring more costs, certainly, we're okay with that.

MR. LANIADO: Also, with the Utility 2.0 proposals having been submitted under a separate proceeding, then the proposals and the entire program has been submitted in a manner that each project would be subject to its own cost benefit analysis of it. Obviously, over the long term of each of those projects, the cost -- the project would only be approved if beneficial to customers, and how that impacts rates in the immediate term would have to be subject to a case-by-case analysis, so, I think we'll have to infer in that situation.

One last issue that I want to point out is we did file the request yesterday with your Honors, for protective order in order to move forward more quickly in producing confidential documents. Many of the materials requested in the discovery in this case are sensitive, obviously, both commercially and with respect to some critical infrastructure information as well as certain other grounds of confidentiality. So, we request, your Honors, I think it would be fair that we request for protective order on all parties on the case as well as your Honors, and forward it to an entry of protective order in the nature that we have submitted.

JUDGE VAN ORT: Just one thing, who requested the information, who requested the information that you're claiming protected status of?

MR. LANIADO: Generally, these are requests that have been made by DPS at this point.

JUDGE VAN ORT: And you're providing it to Staff despite the fact that there's no ruling on the protective order, correct?

MR. LANIADO: Currently, we are moving forward to produce that information to the record's officer under the procedures that we have discussed with DPS.

JUDGE VAN ORT: One of the things that I should point out is that the information being requested, if it's requested by Staff, obviously they're covered by the Public Service Law of Confidentiality provision, so therefore, the information should be provided to Staff. The Staff will not be executing the confidentiality agreement.

MR. LANIADO: That's understood, your Honor.

MS. HOGAN: UIU would like to be heard.

JUDGE PHILLIPS: Yes, UIU?

MS. HOGAN: Yes.

So, before we proceed, I just want to be clear. While I appreciate all of these issues, they tend to be outside the typical rate design. Our concerns are largely focused with -- our initial analysis is looking at the customer charge increase, so I'm assuming that those things will be part of the discussion of the rate design, and I just want to make sure we don't have to list all of those issues now, for example, low income, affordability, and discount.

JUDGE PHILLIPS: (Nonverbal response.)

MS. HOGAN: Okay. That's fine. I just wanted to make sure.

JUDGE PHILLIPS: I'm sorry. I just need to indicate for the transcript that I was agreeing with you, otherwise, it's not reflected.

At this point, I think we have heard all of the parties on the positions on scoping, on schedule, on all of the issues that we outlined for the procedural conference.

What we would like to do is basically take under advisement the request concerning the schedule and scope of issues. I think the scope of issues in particular may be more well-informed as well by the technical conference to follow.

So, what I would like to do at this time is just take a brief recess, and I request that we be back and ready to start by 11:20 by the clock in the back with the technical conference, and that will give us brief opportunity for recess. Thank you very much.

(Whereupon, the procedural conference was concluded at 11:06 a.m.)

JUDGE PHILLIPS: We are continuing at this time with the technical conference portion of this matter. We're going to turn it over to Mr. Weissman who I believe is presenting the technical portion of this. If you would like to begin?

MR. WEISSMAN: Thank you Your Honor. We have on the screen a PowerPoint presentation for the technical conference to lay out the agenda in two separate slides.

What we try to do is we try to set this conference to make all of our witnesses available to answer questions from DPS, and other intervenors, and also, at the same time to present the approach that is taken in the case. So, some people may be familiar with much of this material, others may not, and we try to make it as comprehensive a presentation so that both the case would be explained, and the issues raised in the list of technical conference issues identified by DPS will all be addressed.

I'll make an intermittent introduction. We'll walk through the executive summary of the case, and the major elements of the plan, key drivers of the rate adjustment which is something that the DPS in particular had wanted to have addressed. Then we will spend quite a bit of time, I believe on the public power model. Mr. Falcone of LIPA will be explaining various items of the bond coverage and the phase in of the bond coverage that is planned under the case, the benefits and securitization and the financing plan, treatment of pension benefit costs, also something that has been particularly requested that we address in this technical conference. Mr. Falcone, while he does that presentation, and I'll hand it over to him for that portion will be available for questioning. We'll then talk briefly about the development of the rate plan, how we put it together. We have witnesses from PSEG Long Island who will be available to answer questions on how we develop budgets, and the revenue requirement, and then we'll move on to rate design issues.

Mr. Trainor, another witness in the case for cost of service rate design and tariff issues, will be available to walk through some slides on those issues and to answer questions. Obviously, we're hoping here that all questions can be addressed at the end of each presenters' presentation.

Again, as quickly -- continuing the agenda, everybody has been talking about how this is a relatively unusual rate case, and so, for that reason, we are going to then after going through the development of the budget, the revenue requirements, and the cost of service and rate design, we're going to discuss additional elements of this case, and also, specifically address issues of which the parties have requested that we provide further explanation in this technical conference. We'll discuss power supply issues. Mr. Napoli is here, Mr. Wittine, both witnesses on those issues, will be able to answer questions and describe the power supply portion of the case. Obviously, we're governed under the metric, under the OSA, Ms. Carol Gusick is here, I believe, to discuss those issues.

We'll discuss the degree to which Utility 2.0 is addressed in the case in our filing, and address some of the questions that have been raised. Mr. Volt is here, a witness on those issues and will be able to address those questions on Utility 2.0. Mr. Trainor will discuss Long Island Choice, and questions have been asked about how our consumer outreach resources, and our automatic metering initiatives. Mr. Eichhorn, another witness in the case and Vice President of customer service, is here to answer those questions. Is Mr. Wesley (phonetic) here?

MR. VOLT: No, I'll be representing that part.

MR. WEISSMAN: Mr. Volt will discuss a particular question that was asked about underperforming energy efficiency programs, and finally, moving to the capital area, Mr. Lizanich is here to discuss issues regarding load pocket mitigation, and alternatives to generation, and other infrastructure improvements, as well as questions that have been raised regarding load growth, and load growth in its relationship to capital expenditures that we have included in the case.

Finally, we have a section in the presentation to address New York City's concerns about the FEMA granted limitation, and Sandy issues.

So, I mentioned it in the introduction. There are many people here from PSEG Long Island and from LIPA who are witnesses in the case and technical experts who are here to answer questions, so basically I think with regard to any technical issues that anybody has in the case, I believe we have people here available to answer those questions.

Could PSEG witnesses and experts stand up briefly just so you know who they are. They're all here, and thank you very much for making the time today in your schedules, but if the parties have questions on various issues, we'll know who is available to answer those questions. Thank you.

Just to summarize the case, we filed this three-year plan on January 30th as everybody knows in the context of LIPA Reform Act and the amended and restated operations services agreement, which went into effect January 1, 2014. We made this filing in order to achieve a series of objectives of targeted investments and operations and infrastructure to support customer satisfaction, continued reliability, improve storm response, enhance resiliency. Our goal and our obligation under the OSA is to move from a fourth quarter, quartile utility, improve our customer satisfaction, and other measures to a first quartile utility over five years. We can't do that all at once, but we are well on our way to achieving our goals, as most people are aware, we've had a very successful first year of operation. We've also intended consistently at OSA to achieve customer rates at the lowest level consistent with achieving customer satisfaction, goals, and sound beneficial practices, two percent per year overall rate increase on the total bill is something that we have determined that there was a lot of hard work necessary to enable us to continue to meet our metrics, to continue to provide sound -- safe and adequate service, and also to ensure LIPA's financial health going forward. We're hoping that this -- the needs that we've had thus far, the testimony and the witness that we filed, and the discovery that's ongoing, and anything else that we're continuing to do here, to ensure that it is a transparent and comprehensive presentation of the operations of PSEG Long Island, who is out here for the first time, and Long Island Power Authority for the first time in the existence of LIPA, and certainly for the first time in many, many years that the first time the DPS and the public of Long Island will get a transparent view of their operations of its electric providers.

Some of this stuff has been mentioned. We're going to be funding our investments to achieve the visions of the LRA and OSA for the first quartile performance over five years of moderate rate adjustments. All major rate classes, Mr. Trainor will be able to discuss the rate design issues in detail as questions arise. All major rate classes will receive a two percent increase in total bill for each year, $3.25 per month for the average residential customer. On delivery only rates, it's 3.8 to 3.9 percent of delivery-only revenues per year for the three years of the rate plan. This is following a three year -- three years of no increases in delivery rates, 2013 through 2015. Low income class customers are going to be receiving an increase in their discount, currently $5.00 per month, it will be increased to $10.00 per month for non-heating customers, $15.00 per month for those customers who heat with electricity, and that will substantially mitigate the impact of the rate increase that we've provided.

Again, the Utility 2.0, which was discussed, I guess at length this morning, that is being addressed on a separate track. We have provided testimony in this case regarding what the Utility 2.0 filing is. We'll answer questions in the technical conference as appropriate regarding Utility 2.0. We also are looking to address Retail Choice issues, Long Island Choice, and the recovery of supplied costs in a separate proceeding that DPS are anticipating will receive.

As it was discussed also this morning, no major power plants are anticipated to come online during the 2016 to 2018 period.

Mr. Falcone will discuss the substantial savings that are estimated through the securitization legislation, and that again, Mr. Falcone will be discussing all of the financing and debt related issues including the finance policy that LIPA is pursuing through the filing that will improve its bond rating, reduce debt relative to its assets, and reduce customer costs during the rate plan.

JUDGE VAN ORT: Do you want to wait for questions before the end of your slides?

MR. WEISSMAN: Yes.

One of the issues that DPS has asked us to discuss is a few drivers of the rate adjustment. We tried to break that out, as people are aware there is a $221 million increase in total revenues at the end of the 2018 period. It's broken down into a variety of categories.

First, we're making improvements in our operational and front line services to move us ahead in our customer service metrics, and we're making numerous investments in customer experience, tree trimming and preventive maintenance, our storm response and reliabilities, and that's all resulting from a substantial piece of that increased revenue, same with capital expenditures, infrastructure investment and T and D reliability, a lot of IT investments to benefit customers; things like the operating OMS system for storm improvement that Mr. Eichhorn can speak to. For many of these issues, again, we have experts in the room to discuss each of these items.

There's an inflation increase that is a piece of the overall rate increase. We budget in an inflation of an expected, anticipated less than one percent productivity improvement is budgeted into the budget as provided in the case. There's an increase in the fee to PSEG, which is pre-negotiated in the improved Operating Services Agreement, and that results in a piece of the increase. There are increases in the overall rates over the three years are due, and also in part to property tax increases both with regard to taxes on the delivery system as well as on the National Grid PSA units, costs of which are recovered through the delivery charge. There's also an impact of lower grant income that is reflected in the increase as well.

Finally, there's the investment and debt reduction, which will improve the Authority's credit ratings over the five years, and reduce debt relative assets, and result in an increase, I guess in total of about $30 million over the three years of a plan.

At this point, I'm going to ask Mr. Falcone to come forward and speak.

MR. FALCONE: I'm Tom Falcone. I'm the CFO of LIPA. Thank you for your time.

With regard to this slide, I thought we would spend just a minute on the business model that we have. The reason for that is because we do have a unique business model, it is unlike any other business model I am aware of any other major public utility in the United States. The benefit of that is that you have public-ownership. It's a customer-owned utility. You have a lower cost of capital opposed from that you have the access to federal grants with an investor-owned utility would not be able to receive, both from FEMA and from HUD, and LIPA has been awarded 1.6 billion of those grant units in the last several years. In addition to that we have the experience of a first-class, first quartile utility operator in PSEG. And the experience and also under this OSA contract, their focus and the incentives in the OSA contract of good performance.

It's often a question for people, what are the respective roles of the Authority and of PSEG. The Authority's role is essentially a utility-holding company. We're there to own the asset, and finance the assets on a low cost basis for our customers. PSEG's role under the OSA is to manage the utility on our behalf. They do not benefit from the actual revenues that come off of this rate case. However, those revenue are necessary to fund the budgets that will lead to first quartile utility performance and enhance customer service.

A couple of other minor things that I would mention that are considerable savings, but are not key to the business model. One of which is with the Governor's help, we have proposed securitization legislation in the New York State budget for this year. That securitization legislation will allow LIPA to reduce the cost of its existing debt, and that is anticipated to save approximately $155 million over this rate plan.

One final thing is that one of the issues that we do have at LIPA is higher than average property taxes when you look around the country or even when you look around New York State, and we are pursing litigation to reduce that property tax burden. One of the main points I've put out there is that it falls unevenly on our costumers, so some taxing jurisdictions benefit tremendously from the presense of some of our generation plants and the customers of other taxing jurisdictions are paying for that benefit.

If we could move to the next page. One issue that's often been raised and has come up a number of times here is something called the Public Power Model. In the testimony I submitted in the case, there is an extensive discussion of the Public Power Model.

The first thing I would say is that it's not really -- it's a little bit of a misnomer. It's not really the Public Power Model, it's the Public Sector Model. It's the same model that's used for all kinds of public sector entities to determine revenue requirements, whether you're talking about a public power utility, a water utility like New York City's water utility, whether you're talking about the toll road, a mass transit agency, so this is a very common cost recovery model used throughout the public sector. It is different than what's been used for investor-owned utilities, but there's a good reason for that.

First I'm going to walk through these pages, and then I'm actually going to bring up a page from one of our exhibits to just talk about our actual numbers. What you're going to see on this page is on the left, "Public Power Utility Revenue Requirements." How do you calculate the revenue requirements which are essentially what leads to rates, revenue requirements are synonymous with rates. How do you calculate the revenue requirements for public power utility versus an investor-owned utility, the model which many people in this room are familiar with. It starts off operating expenses, and a public power utility and an investor-owned utility, unsurprisingly, it's the same calculation. And so represented there are our GAAP, normal, operating expenses, add in operating taxes, property taxes, other taxes that we collect on behalf of the State and other jurisdictions. Add in for an investor-owned utility, income taxes, the Authority doesn't pay income taxes because it is a publicly-owned, customer-owned utility. Add in for an investor-owned utility, the amortization of regulatory assets. Regulatory assets, generally speaking are divergences between, I would say cash costs, in most cases cash costs and GAAP costs where someone has said let's take that cost and let's postpone it to the next rate case, or let us amortize the difference between GAAP and cash pension cost, and we'll amortize that in over time. There's a number of examples, but generally speaking, you add that in the investor-owned utility revenue requirement. For the public power utility, you'll see material accruals, it's the same thing, but you see the sign there negative, which is to say that most public power utilities just operate on a basically a GAAP basis, and there is no real use for regulatory assets in the public power model.

However, LIPA is transitioning from a prior model to a new model, and the prior model was a home grown model, which was loosely based on the investor-owned utility model, and so we do have material accruals that are in our expenses that are amortized through our expenses, but they're noncash costs, which you will see in this rate filing is we have made certain adjustments for those, where they are material, and where we believe that we could go to a rating agency investor and show that our cash operating results are better than our reported GAAP operating income. By GAAP operating income, I mean those top three lines. You bring in operating revenues, less operating expenses, less operating taxes, less income taxes.

And so for an IOU you collect your regulatory assets. For LIPA, we've made some for material accruals, we've made some adjustment. Those adjustments reduce the revenue requirement, so if you have no idea of anything I just said, all you really need to know is that it reduces revenue requirements.

The next thing, if you go -- and so you stop there and you drew a line there, you would see that essentially the IOU model and the public power model is the same. Where it's different is how do you collect for your capital costs, the money you put out for capital investment, how do you recover that cost? For investor-owned utility, there's rather a standard method. You get back depreciation, you get your interest expense, and then you have this rate based rate of return model, and that essentially you look at what's in rate base, and you look at allowable return, and that determines the net income, or the profit margin the IOU is permitted. That money, that net income or profit margin is really there to benefit the owners of the utility. In the public sector, there are no owners to the utility. The utility is operated for the benefit of the customers, and so trying to come up with what is the appropriate net income requirement or what is the right profit margin, it's really academic, and it doesn't really translate vert well into the public sector. And so instead what we looked to is power we rated, what bond rating is in the best interest of the customer going to produce the lowest cost to the customer over time, and what cash flow do we need to achieve that. So, rather than recover depreciation expense, interest expense, and then this net income, we recover our debt service principal, the money we sell debt to fund capital projects, we need to recover that principal amount to repay the investor, which is somewhat synonymous, but not the same as depreciation. We still need our interest. We still have to pay the bond holder, and then this thing called debt service coverage. And this is a common metric that is used throughout all the public sector, it's basically just a margin, a margin for error over principal and interest. And so how it's really calculated is if you were take debt service principal and debt service interest, and those lines were a $100, and if we needed a twenty percent margin to maintain our bond rating, if debt service principal and debt service interest equal $100 and covers a twenty percent margin, take twenty percent of that $100, it's $20.

Now the difference is, you get back debt service coverage, that $20 and what do you do with it? You use it to reduce your bond sales. You take the money, it doesn't get paid out to anybody, it's retained for the benefit of the customer. And so rather than, if we have to go and sell or let's say that we have a capital plan whereby we're going to invest in capital, long life capital assets, and those capital assets, we're going to put $50 into the system a year, and our coverage is $20, we're going to take that $20 that we first put in place to ensure the debt holder that there would be sufficient money to repay the debt holder, and then we take that $20, it doesn't double count. What do you do with it after you've assured the investor at the end of the year? You take the $20 you to contribute to the capital plan, so instead of selling $50 worth of debt to fund $50 worth of capital projects you sell $30 worth of debt to fund $50 in capital projects, and $20 comes from this thing called coverage. So, what coverage really is is a way to fund the internally generated funds, or the current year captital contribution to the capital plan to assure that you're not over-levering the utility, that you're operating in a sound fiscal manner. Like I said, this is extremely common throughout all the public sectors, various agencies use this, and if you look at other public power utilities, all the major public power utilities use the same model. All of our pure utilities, and those pure utilities are outlined in what is Exhibit TF12 of the rate plan.

So, with that why don't we go to the next page. So, one thing you might want to do is then say well how do the results under the public power model compare with the results that we would have got had we filed a conventional rate case. You'll see the requested rate adjustments as a percentage of the total customer bill, and I'm just going to focus on the 2016 column. You'll see that's two percent, and you'll see that that delivery rate adjustment is $72 million. Well our net income, which if we were an investor-owned utility, we would be talking about what is our allowable net income essentially, what are we allowed to earn as profit, you'll see our net income under this plan as we lose $60 million.

Previously, LIPA used a rate setting mechanism whereby it had, and I sai there was no good empirical justification for, but they had targeted $75 million of net income every year. That was a standard that worked when it was put in place around 2005, 2006, but it doesn't work consistently, but nonetheless, you see $75 million. We're losing 60. Under the old method, we would have earned 75, that means we would need a $133 million more of rates. If we were to use the conventional investor-owned utility model, that 75 may be a different number, that was our number, but nonetheless it would be a positive number. So there's no real way that you can come out of the rate case and say that, in this particular rate case, it won't necessarily always be like this, but in this particular rate case that you would have been worse off had we used the IOU model, or you would have been better off had we used the IOU modeal and you would have been worse off by using the public power model. You can see the rate adjustments that would have fallen out had we continued with the existing model LIPA used for the 2015 budget, or some variation of it for an investor-owned utility.

So, one other thing I point out is that the savings for the customer over the period, if you go to those cumulative impacts all the way to the right, are $281 million, so rates would have been $281 million higher accumulatively, and the total increase rather than being six percent would have been 7.6 percent, and would have been much more front weighted, so rather than two, two, and two, you would have been 5.7, a little under one, and then another one. So, that is a rough summary of what the difference is. With that, let me go to the next page.

So, in here we've been asked about coverage, and I've already kind of explained coverage. Coverage is just this set, easy to calculate margin as debt service. We use that coverage first to ensure the investor, the bond holder, who isn't an equity holder paid, and gets paid maybe four percent the whole bond for thirty years. They don't want to take equity like risk, a type of risk an IOU shareholder would take. So that coverage first assures the bond holder that they are going to get repaid, and then what it is used when it's an excess fund, it is used to reduce our borrowing for two, three years. And so the question that was presented to us, well why did you phase in the minimum coverage requirements because you see in that box on the page, 2016, '17, '18 and '19, I would first point to that top box, which is called authority debt and capitalized leases, and you see the coverage requirement 120, 130, 140, and after the rate case, it goes to 145 in 2019. What that basically means is a twenty percent, thirty percent, forty percent of debt service.

You also see a second line, which is Authority debt plus UDSA debt plus capitalized leases. So, the way coverage is calculated by the rating agencies and the investors, the people that determine our cost of capital, is that they look at our debt, the debt service, principal and interest payments on our debt, plus our payments on capitalized leases.

We have two types of debt, and we're unusual on that because we are the only public power authority in the country that has securitization debt. One thing I point out is the public power as a whole is a very highly rated sector. The typical bond rating is double A, and yet LIPA is triple B. For folks who aren't an expert, we're rated several notches below the typical public power agency. The one thing about that is that we have two types of debt, and that means that this securitization debt, this the UDSA debt provides our customers with a great deal of savings over if we sell our triple B rated debt. So, you'll see you can calculate these ratios either way on just the Authority debt plus the UDSA debt and really, the run that drives rates is that top line, the second one is the double tray. You say, why do we calculate them both ways, we calculate it both ways because the people, the investors and the rating agencies, as much as we would love to ignore them and say they're not relevant, unfortunately, they determine our cost of capital, and that's the way that they look at this.

So, one other issue that's come up, and will be talked about further here is delivery service adjustments. This term has come up because the way we filed the rate case is really two percent per year plus or minus whatever these DSAs are, delivery service adjustments. These delivery service adjustments, we will talk about later, fall in three categories. One of them is storm costs, and just to take for example storm costs; we budgeted $50 million for storms last year. Over the last ten years, we have spent anywhere from about $20 million to $100 million on storms, so there's a lot of variability around there, and you don't really want to set the rates based on all that variability. So, this DSA basically says well you'll budget for $50 million, and if you come in below that, and set that aside in a reserve fund, and for a year you'll come above it because there is a tendency to come back to the mean over and over again. $50 million is a pretty good average but some years it will be higher, some years it will be lower. So it provides some smoothing mechanism to basically bank when you to are coming below like we did in 2014, we came in about $20 million below budget, bank it for the year coming above. If you come in above, divide it by three, and you'll recollect over three years.

The second category in the DSA is power supply costs that in our delivery rates. Limited to only the JCO units, the historic gas fire units that used to be part of LILCO that are owned by National Grid plus nine-mile-point-two. Once again, there's some uncertainty there. However, we do know, once again, it's a customer-funded utility, so ultimately the customer, there's no one else to pay the costs if the cost of power supply comes in higher or lower. Most of our power supply costs are in something called the power supply charges, changes of every month. For these delivery service adjustments, they deal with the portion of power supply that is just in the delivery rate, and all it's really intended to do is to have a more current cost recovery mechanism to the extent they come in higher or lower, and we believe because we have forecasted considerable property tax, or some property tax savings, bet we believe we may have achieved considerable property tax savings through the rate case.

In this case, that delivery service adjustment is a mechanism by which to give customers lower rates over the period because if we had to file a rate case today, we would file the rate case based on our expected property taxes without taking into account the savings. And we would be giving any savings that we achieved back sometime after rate case delivery.

Finally, the third component of delivery service adjustment is debt service cost because we have filed rate case whereby we assume significant debt service savings because we have a lot of bonds that are refundable. We are getting securitization legislation, and we would like to rebate those costs back to the customers as quickly as possible. However, if we had to file the rate case based on our existing cost of debt without taking those refinancings into account, the rate request would be much higher. So, we filed the rate case based on what we would believe would be a reasonable and conservative budget for debt service for one that takes into account savings.

So, in all three of these cases, in my mind, what the delivery service adjustments facilitates is us setting a lower revenue requirement. It allows us to budget at rates that we believe are reasonable rather than more conservative. And the other thing it does is it allows us to budget at lower coverage levels because why do you have coverage in essence for the investor, for the debt holder, it's to assure that if your budget estimates are off, you still have money to pay them. So, if you're not taking that risk in your rates, you can set that coverage factor lower, so we think that DSA factor allows us to set lower rate requirements. We also think that's consistent with sound fiscal operating practice, and it's also consistent with setting rates at the lowest possible level for our customers that is still sound fiscal operating practice.

Going on to the next slide, this will be my final slide but then I'm going to bring up one exhibit and also take your questions because I know you will have some. We have pending -- this gets back to this debt service. So, we have debt that is outstanding and we belive we can significantly lower the cost of that debt through refinancing. The way that we'll achieve that is through a bill that allows us to sell triple A rated bonds to refund triple B rated bonds. That debt is callable between now and 2019. Each of the years of the rate case, there's a certain amount of debt that can be refinanced. The one thing that's different if you're familiar with a home mortgage, for example, is that a home mortgage you'll go out and get a home mortgage for thirty years at five percent, if the rate drops to four percent, you can refinance it tomorrow. That isn't the way it works in the debt market. There are things called call features. So, you can't refinance the debt until a certain date. The investor knows when they buy the bond, they have a certain period whereby they will own the bond, but we have all these bonds that are reaching their date, two and a half billion dollars of bonds that are reaching their dates that they can be refinanced, and that they have significantly above coupon -- they were on-market at the time that they were sold, but now you fast forward ten years and interest rates are lower, will be able to refinance that debt at lower rates.

So, the question that sometimes comes up is, are you stretching the debt, and no. If you take an example, if you have a home mortgage, if you took out a home mortgage ten years ago, and that home mortgage was at a rate of five percent or thirty year loan, now your ten years into the loan, you have twenty years left, and you go to the bank, and the bank says, I can refinance that loan at four percent, do you want to take out a twenty year loan or a thirty year loan? Do you want to take out another thirty year loan or do you want to take out a twenty year loan, you are ten years into your thirty year mortgage. We are taking out the twenty year loan, the interest rate is lower, we're not stretching the debt. You can see that on this example. The light blue line is somewhat hard to see on the graph, is the before. The dark blue line is the after. For the existing debt, and it's the same or lower in every year and then add on the new capital that we sell. So, you might say well your debt is going up because that's a question that's come up. We are going to finance $1.9 billion of capital improvements on the system over the next three years. Our current property, plant and equipment is about $7 billion. We are going to add close to $2 billion, $1.9 billion, and of that, our debt is going to increase by about $400 million, that's pretty good. That's facilitated in large part because we achieved a grant, and that grant will pay for ninety percent of a storm hardening program. So, that's money that is available to us that wouldn't be available to an IOU, but is available to the public power industry, so that's great; but the other thing we're doing with that increased coverage is we're getting to a sustainable level where about sixty percent of our capital going forward will come from rates and forty percent from debt, which is a very standard mix across the public power industry, and across the IOUs, frankly, for how much capital for your long-term debt, and how much should be funded from debt, and how much should be funded from equity.

Unfortunately, because of our history at LIPA, we're a takeover investor-owned utility, it started out as a hundred percent debt financed utility, and now it's a ninety-seven percent debt financed utility, but over about twenty years, this plan will reduce the debt to a very standard industry median level as a percentage of assets. That is really what we focused on in looking at this rate plan. We are not levering up the utility. We're looking at what is reasonable, what is reasonable relative to the investments that we are making because we would still like to make investments that benefit the customers. We don't want to ramp down on those, but we want to make sure that each and every year, we're making a prudent contribution from customer rates towards that and not adding too much to the debts.

With that I'm going to bring up one of our slides, RRP2. Actually, I'm going to come back to the pension -- well, actually, let me deal with it now. So, I'll just talk for a second about pensions, and then we'll switch to the other one, and make it easier.

The thing about pensions and retirement benefit costs. This has come up in the media a lot, so let me just explain it for a brief second. The Authority has roughly forty staff members, employees. We are all State employees, so we all participate in State retirement benefit plans for members of the State's pension plan, and everything else. So, we don't have a separate pension plan, our retirement costs are basically paid in per year. Since we only have forty employees, frankly, these aren't where the bulk of the liabilities sits.

In addition, there are about 2200 employees of PSEG Long Island. Those 2200 employees of PSEG Long Island are dedicated and work for essentially LIPA. They work for the Authority. One might say well, and they have always been there, that would be the other thing I would say. These 2200, probably about 2000 of them used to work for National Grid under a similar arrangement. So, we have a fellow that he was describing to me his career and history. He runs our substations for PSEG Long Island. I was asking about his career, and he said, you know, I've worked for five companies in my career, and I've never changed my phone number, that's because he worked for LILCO, he worked for Keyspan, he worked for National Grid, and now he works for PSEG. My point is these employees are based on Long Island, they maintain the Long Island electric system, and they work on behalf of LIPA. So that is where the bulk of the pension and retirement benefit costs is because that is where the bulk of the employees are. So, those employees under National Grid were either members of a collective bargaining agreement, or they had established pension plans, and when we trade service providers to provide improved service for the people on Long Island, we said well hold the workforce constant, don't harm the benefits, these people have worked for LIPA in its various forms, or LILCO, it's predecessor, for fifteen, twenty, thirty years, and so, you're not going to change the benefits just because we've decided to change service providers. So, they have received the same benefits they would have received under National Grid. They don't receive a better benefit, and as a matter of fact, non-union new hires under PSEG are no longer eligible for pension plans, they just receive 401ks. But if you had a pension plan, you kept your pension plan. Those liabilities, those pension plans, retirement plan liabilities, are an obligation to PSEG Long Island as a corporate pension plan.

However, under the OSA contract that we have, the Authority is responsible for the cost because that OSA contract is a cost clause contract. We pay PSEG's cost to operate the system on our behalf, and then we pay them a management fee, and that management fee has incentives, if they do a good job, and disincentives if they do a bad job. And so the Authority seeks to recover the cash contributions to the PSEG Long Island pension plan.

That's a little different than for investor-owned utilities. Investor-owned utilities will cover the GAAP costs. There's a whole host of reasons for that, that I'm going to skip unless somebody has a question. It's all covered in the testimony, but what I would say is by covering the cash contribution cost, the results in rates are lower, however, it still fully funds the benefits. If you get into the details of the accounting, we could go through it, but it really is a detailed accounting exercise.

I would say the same thing for OPEB. OPEB is the name for retirement benefits, Other Post Employment Benefits. We have a contractual liability to pay retiree health care, retiree life insurance benefits that have been promised to PSEG employees. We established an OPEB account, fund those, and we are making contributions out of coverage. That margin that we have, a portion of that is going to go to this OPEB account to prefund those liabilities, and a portion of that is going to reduce our capital plan.

With that, I'm now going to flip over to one of the exhibits, that was in the testimony, RRP1 is the exhibit. I'm only going to spend a second on this page. It's very small unfortunately, but you can download it off of the DPS website, and as you can see in the top right corner, it's called Exhibit RRP1. I'm really going to focus down at the bottom line, excess of revenues over expenses, and you can see $75 million in 2015, and negative 58 million in '16, negative 16 million in '17, and goes to positive 18 million in '18. This is a fairly conventional presentation for an investor-owned utility. In an investor-owned utility, the question we would be sitting here is, how much can you earn, that bottom line. I'm simplifying a little bit, but not by much. How much is that excess of revenues over expenses, what we might call net income? What's the possible allowable number that we would be permitted, that would be our debate. Yet, I'm here saying that we will get a credit rating upgrade, we will reduce our leverage, we will adequately meet our obligations, the utility will be less burdened than in twenty years from now that it is today by debt, it will provide a lower cost to customers over the long term that is economical to the customers, and we will lose money. So, that may seem counterintuitive, but all I can say is it works and it's very conventional. Someone once told me a joke about the definition of an economist, and they said that an economist is someone who takes something that works in practice, and tells you why it doesn't work in theory. This is a very established practical method that is used by the entire public sector, and by all of our private utilities.

MR. WEISSMAN: The Judges established the technical conference for the purpose of give and take, and I know we've been talking quite a bit. If there are any questions about the public power approach, Mr. Falcone --

JUDGE VAN ORT: Can we just get a show of hands as to how many people have questions on this issue? Okay. Would you please use the podium over here, so you can use the microphone as you speak because we want the reporter to capture everything.

JUDGE PHILLIPS: Just turn on the mic before you start. The green button needs to be on.

MR. BJURLOF: My name is Tom Bjurlof. Just a couple simple questions.

Obviously, one of the difficulties that the Authority has had is to sort out the property taxes, particular on the legacy plans. I assume that under the investor-owned utility model that would probably have been taken care of a little faster, but granted what you're presenting as the proper model, and I have no disagreement with that, I would like to ask you a simple question; if you were to take out all of the fixed costs related to power supply, how would that change your numbers? I'm curious to know what the impact is or actually if not entirely in effect of owning all the power plants?

MR. FALCONE: This is an interesting question, and to some degree gets into power supply questions. I don't want to go into a conversation of whether we should own the power supply or not. I think that is a topic of conversation that belongs on a separate track that we discussed earlier with Long Island Choice.

With regard to property taxes, part of the reason for that delivery service adjustment is to the extent that we're currently litigating property taxes, and that we win, and we reduce costs, we will be refunding that lower property tax bill to the customer immediately through that DSA as opposed to waiting for the next rate case in 2019.

JUDGE VAN ORT: Mr. Brindley (phonetic), do you have questions?

MR. BRINDLEY: Yes, I do.

This is more in the way of some commentary in trying to take the stuff that Tom has talked about and relate it to terms that we're much more comfortable with, but I do want to make some initial points.

First, I want to make one initial point on the very -- on slide five you talked there were no delivery increases in the past three years, I could swear there was a delivery rate increase last year, and there will be another one this year. If you wanted to say there was no increase in the non-fuel portion of the customers' bill, I would agree with it, but as far as I know there were delivery rate increases last year, and there will be one this year.

MR. FALCONE: That's correct, it's really the non-fuel -- which sometimes we will in our artfully term the delivery rate, everything that's not part of the power supply charge, and so when you take the entire non-power supply charges, those are flat, but there is changing among the components and I think that's something the Department of Public Service had recommended last year, but also reserved the right to look at, so we're looking at that as part of the rate case.

MR. BRINDLEY: Okay, I just wanted to be clear on that. The first slide I would like to look at -- and just to be clear I asked Tom at the very last minute today put up the last two slides that he showed because I thought it was important for us to understand how his methodology relates to what we traditionally do because it is different, but it can be converted to something similar to what we do.

One slide before that please. I want to make another point though. Tom, you mentioned that one of the reasons you want coverage is for uncertainty and estimates, to perhaps provide you a cushion. When I looked at the income statement here, almost every single line already has a built-in cushion, and I just wanted you to comment on what I'm missing, or maybe perhaps how I should be interpreting it. When I look at the revenue line, you have a risk mitigation device called an RDM that will help assist you when sales drop, for example, for purposes of energy efficiency, so there's one risk mitigation device. When I look at the second line on the exhibit, we're talking about fuel. There's a fuel pass through clause. That's another risk mitigation device. We get over to PSEG operating expense. Well, there, basically that's PSEG's costs, and if they want to make their incentive metric payments, that's going to pretty much have to come in on target, or no more than two percent, so that's another risk mitigation device. When I look at the next line on the income statement, PSEG Managed Expenses, it looks like out of that 584 million, 465 relates to the PSA, and you're asking for a DSA on that. Also, there's another 48 million in there that relates to storms, and you're asking for a DSA on that, which leaves not too much other money in there, but again, that's protected by another risk mitigation device with a two percent cap. Utility depreciation, we'll talk about that a little more when we get to the public power model. The pilots on the revenue based taxes, there is no risk on that, that's just a flat rate, so no matter what happens with the revenues, that will track it. The property based taxes, these are covered by the legislation from last year. They can't go up more than two percent, so there's another risk mitigation device. When I get down to LIPA, what their expenses are, the 133 million, 73 million of that is the MSA, that's set by contract. That isn't going to change, that's the number, and then you have another 50 million in there for deferrals, which is also handled in the public power model a little different. So, when I come down, I see a risk mitigation device on almost every single line of your income statement with the exception of other income and grant income. Does that sound about right because you're telling me you need coverage?

MR. FALCONE: So, a couple things. Number one, and that get's into this DSA. We've set the DSA in 2019 at 145. Typical for a utility of our rating would be 175 to two, so typically, you would have a much higher margin, probably about double the margin that we're asking for, and so, yes, we have some of these devices and if we set our rate to achieve 175 coverage, we would just absorb some of the other risks.

On something like RDM, that is relatively standard policy, does mitigate weather risk, it's also a device to deal with increasing Utility 2.0 expenditures, expanding energy efficiency budgets. If you look at something like property tax, we have mitigation devices on our own property, but half our property tax bill roughly is National Grid plans, and there is no protection there. The only protection we have is litigation. With regards to that litigation, the outcome is uncertain, although we feel pretty comfortable that these plans are very well overassessed, and that we have a very good case.

MR. BRINDLEY: But you have asked for a DSA on that.

MR. TRAINOR: In that case, the DSA will likely result in a -- because we've only assumed 8 million -- 0 in '16, 8 million in '17, and 16 in '18. These plans are extremely overassessed. It is more likely in my opinion, and it is just a view because no one can anticipate litigation, it is more likely that more savings could come back rather than less, and that the DSA could result in more savings coming back to the customer rather than less.

On something like storms, you're correct in that PSEG Long Island has to come in within two percent of their budget except in their contract, for say storms, those are all pass-through expenditures. So, if we spend $100 million a year on a storm, and we only budgeted 50, that's $50 million, so there has to be -- the one thing I would say is that we're a public power utility. There's nobody else. It's not like there's a shareholder to take that $50 million risk. Eventually, one way or the other, it's only the customer. The customer gets all the benefits of a public power approach, but they ultimately take the risk as well. So, there has to be some way to recoup storm costs from the customer one way or the other. PSEG did not accept the risks of storms because nobody can anticipate storm costs, and so, those are all pass-through expenditures to us, and there is no risk mitigation on that.

Even within their two percent cap, while they have a two percent cap on their operating budget, the contract has certain exceptions to it. In the event, for example, non-storm emergencies, and last year we had two small non-storm emergencies. There was a cable outage. So, there are certain things in the contract that they said are so inherently unpredictable that they fall outside of the two percent cap, but on those, we take the risk. So, if there's a non-storm emergency, LIPA takes the risk.

So, the MSA is a cost plus contract at FERC regulated rate. However, property taxes are all pass-through, pension costs are all pass-through, so while their operating budgets are set in advance at FERC regulated cost of service rates, they are readjusted from time to time, and there are certain pass-through costs there.

One thing we are not doing, and debt service is one where we have a huge unknown in that we are budgeting what we believe to be reasonable savings over this period because we would like to give them back to the customer. However, interest rates, legislation doesn't occur, we may not achieve those savings, and so, we are trying to budget what we think are reasonable, and those DSAs facilitate us setting what are reasonable budgets, but also using much lower coverage metrics than we would normally be able to achieve for our ratings; something like 120 in '16, going up to 145 by '19, rather than a number that's closer to like 175, so if we were to set rates to a much higher coverage margin, we could get rid of the DSAs, and we would be fine. This is really what you end up paying for. Is the customer better off by setting rates to lower margins with some pass-throughs or to a higher margin? They're basically -- how much insurance do you want to buy, that's the fundamental conversation.

MR. BRINDLEY: The coverage ratio in a cost of service model would be called the rate of return, that's really what it is. What I take from what you're saying, Tom, is given all of the risk mitigation devices that you have in the income statement, you've decided rather than -- you can reduce what is a reasonable coverage ratio from 1.75, 1.8, whatever it is, down to 1.2?

MR. FALCONE: 1.2 increasing to 1.45?

MR. BRINDLEY: Right, that's where you're adjusting because you have all these risk mitigation devices you don't need what you might otherwise need. If we didn't have these, you would ask for more coverage.

MR. FALCONE: Correct.

MR. BRINDLEY: That's really the point I was just trying to ge to because it's very difficult to really try and understand the public service model in comparison to our cost of service, and the analogy to me is your coverage ratio is the rate of return, which is typically one of the most controversial items in a rate case.

MR. FALCONE: One thing I would mention on that is that it is an analogy, but the difference is that the coverage is attainted for the benefit of the customer, unlike an IOU versus paid out to a third-party shareholder. So, essentially, that coverage first provides the assurance to the investor that they'll get paid on time, but then it reduces our borrowing, and so it leads to less leverage utility, which leads to lower rates over time. So, by giving the investor, the debt holders, some assurance they will get repaid, we get lower interest costs, which is in the benefit of the customer, and by having less future debt you get lower rates in the future as well. So, this is a plan that as carried out will result in lower rates in the future.

MR. BRINDLEY: Right, which is what now, you're doing some internal funding as opposed to going outside and issuing more debt, which has been a sore bone of controversy on Long Island for as long as I can remember.

MR. FALCONE: Right.

MR. BRINDLEY: Let me switch to the next page. This is the page, it's the second page, RRP1, page two, it's where they calculate the revenue requirement for the rate case. There's an awful a lot of shorthand in here, but what you can do is you can take all the shorthand that's in here, and blow it out into a traditional cost of service model, and understand basically what the company's earnings are. You can then take the LIPA debt service and their capitalized lease, apply the rate of return, which in this case is called coverage, come up with a required earnings, compare that to what happens here, and wala (phonetic), you have the revenue requirement. Just so you understand what we do in a more traditional fashion.

What is different in here is that depreciation does not enter directly into the equation, bulk interest does not enter directly into the equation, amortizations of regulatory IOUs do not enter directly into the equation. The way the company collects this money basically is via their debt service coverage, and as Tom has explained, the debt service coverage consists of principal and interest. So, the principal portion of the debt service is analogist to recovery of depreciation, amortizations in a rate case. The timing will not work exactly because you got debt, you got money out there, you got to work the money out there, but that's essentially where they're collecting their depreciation and amortization in the principal portion. The other piece is the interest, and that's just like you get interest in a regular rate base recovery, so you have vehicles here to make this look more analogues to what we do on a cost of service. I think that's important because that's really where all of our institutional knowledge is and whether we find comfort or not with Tom's proposed methodology here. I'm not pro or con here at this meeting, I'm just trying to make sure that you understand it because you will be looking at it, and you can take all of the shorthand, and make it look like something much more analogues to an IOU.

MR. FALCONE: We like the shorthand, but I agree with your analogy.

MR. BRINDLEY: You got a lot of shorthand going on there, Tom.

I think I'll stop here. I had another line on your levels of debt, but I don't want to belabor any more points here.

JUDGE VAN ORT: We have anyone else have any questions? I don't see any hands.

Mr. Falcone, I have one question, you had mentioned that you believe that the property taxes -- you have over-assessments, significant over-assessments, is this review of the over-assessments, is this done in-house, or what's the process, do you contract out?

MR. TRAINOR: No, it's currently being litigated, so there is ongoing litigation that we think will come to fruition during the term of the rate case, probably not, certainly not before the rate case is complete here this year.

JUDGE VAN ORT: My question is a little bit different, what is the process, is it in-house counsel, is it in-house engineers, how is the review done?

MR. TRAINOR: We contract it out to prepare for litigation, and had someone look at the plans, and look at what a proper assessed value should be on the plans.

JUDGE VAN ORT: Is the service performed on a contingency fee basis?

MR. FALCONE: No.

JUDGE VAN ORT: It's straight hourly?

MR. FALCONE: We hired a consultant to come in and evaluate basically what the plans are worth.

JUDGE VAN ORT: I'm referring to the litigation, when it's litigated.

MR. FALCONE: No, there is no contingency fee basis. This is an equivalent to say a homeowner that is -- that the person is going to reap the reward. We hire counsel, and that counsel represents us in the case.

JUDGE VAN ORT: Thank you. We have next, Mr. Weissman?

MR. WEISSMAN: Thanks Tom. Next we're going to discuss the development of the rate plan we have within the company. I guess the testimony that has been provided, we represent each of the PSEG Long Island operating divisions, the transmission and distribution, customer service, shared services, power supply, and energy efficiency groups, each develope their own operating and capital budgets, those are described in the testimony that we filed. Those budgets will then turn into revenue requirements, and rates, incorporating input from the HR group, the testimony in the case from the -- I guess it's called the wages and salaries panel. There's also testimony of Mr. Ahern is here in developing the revenue requirements. There's a sales forecast that we made, and obviously, the sales forecast was made assuming revenue from those sales and current rates are put into the case, and a revenue requirement is developed from the budgeted costs over the 2016 through '18 period as compared with how much revenue would be recovered under projected sales.

The revenue requirement is then run through a cost of service and rate design process, and I suppose we have the people here who developed these budgets, and revenue requirements available for any questions that people have with how those budgets were developed, how the sales forecast was developed. Mr. Figliozzi and Mr. Ahern are here, Mr. Eichhorn is here. Mr. Figliozzi and Mr. Ahern are budget experts, and help developed the revenue requirements, and Mr. Eichhorn developed the sales forecast, and we're happy and available for them to have questions on how that was done, and obviously, discovery is ongoing.

JUDGE PHILLIPS: So, are you just basically asking by show of hands if anyone has questions, so that you can move forward?

MR. WEISSMAN: Correct, Your Honor.

JUDGE PHILLIPS: Show of hands? Can you come up to the mic, please?

MR. HARRINGTON: Mark Harrington from Newsday, is there a cap on the DSA in terms how much it can increase or decrease at any point?

MR. FALCONE: Let me just address the DSA. There isn't a cap proposed, however, at the same time, there's an actual cap, which is that it is based on actual cost. So, you have to incur an actual cost that's different than the budgeted cost.

There is only three categories of such cost and in each case let's look at what those components are. In one case, it's debt service, so we could've filed the rate case assuming the current debt service as scheduled, and not take into account any of the refinancings. And then sometime around 2019, we could say well, we over-collected by $155 million or something, and we could refund it back to the customers. So, we've made pretty reasonable projections, they're not certain, but that is the goal with the delivery service adjustment.

With regard to storms, they're unpredictable. Ultimately, it is a customer funded utility, so there's no one else but the customer to pay for the cost of the storm, and there's an actual smoothing device in there, and it's a reasonable estimate if you look at our historic storm spending.

With regard to the National Grid contract, the Genco (phonetic) contracts, there are certain uncertainties in there but, you know, these things are bounded because they're based on actual costs. One of the biggest uncertainties with regard to National Grid is the property tax litigation that I already mentioned, and we've assumed a very, very small amount of savings for property tax litigation. It could come out to be much larger.

I think one of the issues is that we're all focused on how it could go up, but it could just as easily result in a number that goes down. The number that's assumed in the rate case filing for what the DSA number will be over the three years is zero, and we'll assume it will be zero. It isn't bounded, but at the same time it is bounded by, you have to realize an actual cost in excess, and these are all costs that would be normally recovered from the customer. So, the issue is not whether you recover the costs from the customer, but the time period of which you recover the cost. Do you recover it during the rate case period, or do you save it up and recover it, start and mound on it and roll it up to 2019, and then recover the cost in 2019 at the end of the period?

MR. HARRINGTON: Can you give a best and worst case scenario for how that could change?

MR. FALCONE: If you look at my testimony, table four.

JUDGE PHILLIPS: You have to come up to the mic.

MR. BJURLOF: I just want to point of clarification, on the revenue decoupling, are you assuming that there will be rate cases every three years, or is this the only rate case that we will have, except if you go over the 2.5 percent in the LIPA Reform Act?

MR. FALCONE: The revenue decoupling, let me just for the benefit of anybody who is less familiar with it. It's something that the Public Service Commission asks for all utilities in New

York to put in around 2008, or so.

It is really a mechanism that deals with, in my mind, two things. One of them is to the extent that we pursue more energy efficiency than is currently in the budget, and it results in lower sales, there has to be a method to recoup the lower sales, otherwise, you can't pursue the energy efficiency.

With that said the energy efficiency, we have already built in budgets, and those budgets assume no energy efficiency benefit from Utility 2.0. So, Utility 2.0 is already in the rate case from the perspective that we assume there's no benefit from it. To the extent that we then pursue Utility 2.0 solution that costs less than what's existing in the rate case, it's likely to have resulted in lower sales, but it may also result in lower debt service because you've gotten rid of a debt service cost. Right, you issued less bonds to fund a new substation. Let's say you got rid of the substation, that is going to result in less debt service, in which we accrued up by the DSA, and then you may have efficiency spending on the other side, so you really have to look at all these things together.

MR. BJURLOF: That's not my question, and I don't have any objection to revenue decoupling. I actually think it's a good idea.

The ability that the utility gets through revenue decoupling is to continually adjust rates if you don't meet your revenue requirement. Now, that requires some kind of regulatory mechanism, and normally that's done in a traditional rate case every three or, I don't know, four or five years, whatever the rate case is. If I understand the LIPA format properly, this may possibly be the only rate case or rate plan proceeding that we enter into except if we somehow break into the 2.5 percent limit on an annual basis, so the question is, what is the regulatory control on ongoing adjustments because of revenue shortfall?

MR. FALCONE: I don't see DSM as in any way helping us avoid a rate case or having any impact on 2.5 percent cap.

MR. WEISSMAN: At this point, Mr. Trainor, who is our cost of service rate design witness in the case, will walk us next through the slides.

MR. BRINDLEY: I still have a question for Tom.

MR. TRAINOR: I'm just answering his question for clarification and then I'll jump out.

To answer your question, this part is in my testimony, that's I volunteered to answer the question --

JUDGE PHILLIPS: I'm sorry, I have to interrupt, but you have to kind of have to face the microphone.

MR. TRAINOR: This is Justin Trainor. The answer to your question is that after the three-year rate plan, the budget for LIPA is approved through the board process. As the budget is approved, the revenues and the expenses are in that budget. The RDM envisions that that budget approval process will reset the targets for the RDM after the three-year rate plan, so the LIPA board will still retain control of the budget.

MR. FALCONE: If you could clarify to, if the target requires greater than two and a half percent, then you still come back to the rate case. The RDM doesn't impact the two and a half percent cap that you illustrated?

MR. BJURLOF: So, what you're saying is that what I just stated is that this may be the only rate case that ever happens for LIPA, given that we stay inside the 2.5 percent; is that correct?

MR. TRAINOR: As Tom just described, the parameters for which we come back are set outside the revenue decoupling mechanism if the revenues are such that it all goes over the 2.5 percent limit, which I can't say at this point is yes or no, we will be in another rate case, and at that time the RDM will be set at that time.

JUDGE VAN ORT: Mr. BRINDLEY (phonetic)?

While he's walking up here, do we have anyone else who has any questions at this point? When Mr. Brindley is done, Mr. Weissman, can you move on to the next set?

MR. BRINDLEY: Two questions, first on the ambiguity of a rate case, but correct me if I'm wrong, but you have numbers in the rate case, you're requesting an increase in part for a rate case starting right after this one is done. So is there any ambiguity that you're going to make a major rate filing following this one?

MR. FALCONE: It's hard to predict the future, but if I were putting bets on, this is not our last rate case.

MR. BRINDLEY: Well what I'm saying is you have part of your increase is for the next rate case. In your case currently, you have projected expenses for the next rate case. Yes or no?

MR. FALCONE: Oh, yes, we actually do have -- you're saying expenses building for rate cases, yes, we do have money built into the budgets future --

MR. BRINDLEY: For the next rate case?

MR. FALCONE: Yes.

MR. BRINDLEY: I just want to follow-up a little bit on Mark's point and it's for you Tom. Right now for your DSA for the PSA, which there is too many acronyms here, you have roughly $8 million I think in savings within the last two years for property taxes. Take the number, what happens if they don't materialize and you don't have a DSA?

MR. FALCONE: To put things in perspective, the property taxes on those National Grid plans are about $200 million year. There's zero savings in '16, 8 million assumed for '17, and 16 million assumed for '18. To the extent that the savings aren't realized, and we don't have a DSA, then what would happen is we would end up issuing bonds for -- because we would have lower coverage, and so it would basically mean we have less capital contribution to the capital plan, and we end up issuing 8 million, 16 million more in bonds for those years. I think $8 million is not enough to make a difference for --

MR. BRINDLEY: It's a illustrative, you know, I can make it $80 million for purposes of the example. The way I would be thinking of it is that, I'm not pro or con here I'm just trying to explain math, but my understanding of your rate making process is, would you not realize those savings, you would have to go out issue debt that would then increase your future need for coverage and debt service.

MR. FALCONE: Right.

MR. BRINDLEY: So, the customer is going to pay for it one way or the other?

MR. FALCONE: Correct, I mean these are all costs that ultimately since there is no one else but the customer, the customer will end up paying the cost; not because we wouldn't love to find another method, but because there is no other source.

MR. BRINDLEY: Thanks.

MR. WEISSMAN: Mr. Trainor.

MR. TRAINOR: The first slide we have is the revenue decoupling slide, and we did cover mainly this already, but there are a couple of items here on this slide that I would like to address. It's more of not the issue that we were just questioning, but more of the mechanics of it.

What we're talking about with the revenue decoupling again that's being presented to the LIPA Board for an implementation in April, is that we would have a true-up mechanism based on the first -- essentially months from April through January -- December of '15. The true-up would be calculated and then implemented in March as a rate change based on the percentage of the delivery charges on a customer's bill. So, we would take the revenue that were either over-recovered or under-recovered, we convert that into a percentage by essentially rate groups, so residential, small commercial, non-demand, commercial demand, and commercial multiple rate period. We would identify a percentage for those particular groups, and again it would be based on their actuals over or under-amounts compared to their budgeted revenues. We would apply that percentage to the future rate for the next six months then we would true-up again another six-month period.

Now, there is a provision that if that amount of revenues in the budget is not tracking to the amount in actual, we do have the ability through an out of bounds task to start or manipulate those percentage changes early, if in fact, the money are again out of line to a great extent because of some unusual event.

Now the one thing I do want to address here is that in revenue decoupling, in others, this actually does affect the company's earnings or the amount that is taken out of the company by an IOU. Again, since this is a municipal utility, there is no person on any one point in time at extraction of money from the utility into a third-party. Any moneys that would be collected or assessed because expenses had changed, would then be used for the benefit of future customers. So, we don't have an earnings test, we don't earnings essentially going to a third-party in our revenue decoupling mechanism. Again, we don't have earnings as a municipal utility.

JUDGE VAN ORT: Does anyone have any questions with respect to this issue? Okay.

Mr. Trainor, I do have one question, are all service classes subject to this, are there any classes that would be exempted from the reconciliation?

MR. TRAINOR: New York State has sort of a revenue decoupling. Revenue decoupling is sort of a statewide revenue decoupling process. We are following that revenue decoupling process to the extent that we can. We are similar and in that, negotiated contracts, discount rates, those are excluded from the RDM mechanism, and we do exclude those as well.

Next slide, what I want to do is go over some of the rate design configurations that we're proposing in the case. This is the company's proposal to change the rates without being just on a pro rather basis for all of the components of the rates.

What I would like to do is start with the residential. In the residential, I have a slide later on, we're asking for a customer charge increase from essentially $10 a month to $15 a month. Now, in New York the normal customer charges rating for the other IOU utilities start at 15 and then go north from there. So, in recent cases the Public Service Commission has authorized more than $20 in a customer charge for other gas or electric utilities in the state. So, what we're proposing here is on a gradualism basis is bring our customer charge up to what other utilities in the state have their customer charges set at.

Now, we didn't want to burden or confuse the issue between the customer charge impact and the low income impact. We are coming in with a proposal that would greatly increase the customer low income discount. In fact, we are mirroring the $5 increase in customer charge request for the $5 increase with the low income request. So we are then actually expanding it to an extent for customers that have heat, or electric heat we're increasing that to actually $15. So, essentially even with our request of $15, residential low income heat customer would not really receive a customer charge. In fact, my proposal is a penny, which is about 30 cents.

With that, I'm also trying to bring the utility into a design of a utility that is unbundled, where LIPA has been a bundled utility for all of its existence, it is now a fuel power rate, which brings out fuel, and capacity or to the extent, that it's not on the PSA capacity calls, into a separate charge or the FPPCA.

Now, in that, LIPA's rates have a seasonality to them. They have a cost in the summer that is more than a cost in the winter. However, delivery costs are not subject to that seasonality. Delivery costs, or debt service costs, or the cost to employee. Our employees is 2,000-plus employees. That number is static throughout the year. So, in delivery rates, it's normal that you don't have a seasonality, that you just collect the moneys across the year in one thing.

What I'm trying to do is eliminate the seasonality by including a flat block structure. So, right now we have winter rates that have a declining for general heat customers and an inclining in the summer. What I'm proposing is a flat rate structure where you have just a customer charge in one set number. If you can do some quick math, the customer charge is going up by $5, the first year's request is $3.25. In fact, what happens is we're asking for the rate request in the customer charge and the energy rates in total are actually going down.

The next proposal on the slide is we have some issues with our rate codes. In LIPA, we have rate codes for identification of whether you have a heat pump or heat, central heat, or we have an indication of whether you are heat, or in some other way have water heating or not. This is very confusing, not only to our customers, but for our own purposes. What we are proposing here is to clean up our billing system. These rates for these various customers are all the same right now. We're not suggesting that we change any of this rates for these customers, we are just eliminating the rate codes to bring all the rate codes into either a 180 or a 580 rate code. Right now, we have ten such rate codes which we would be combining.

Again, we have one other feature, which is the elimination of some grandfathered rates that we have basically back from 1983. The grandfathered rates would be such that there is a block in the mill, which actually goes down, and again, as I said, the new rates that we are proposing, a customer on those rates are going to see an energy rate decrease. So, even grandfathered customers would actually see a benefit undergoing under this new flat rate structure than they would if they stayed on their grandfathered classes. Again, the customer charge is where the rate request is, and that benefit of that customer charge going increase, is that the energy rates on the pole are coming down, and that is benefit, not only to our general customers, but to our grandfather customers as well.

The last point on the slide is that the, via the fact that the rate design is such that the energy rate is going down, a customer's rate request is more like $5 in the winter months, and actually zero in the summer months. The benefit of this charge or this rate design is that the customer bills right now would actually be flat for a customer even with a rate decreased in the summer. We have about forty-five percent or 450,000 customers on balanced billing, and our customers really see that paying that extra money in the summer is a burden. I didn't want to burden them more by going to this rate proposal by putting more money in the summer rates. This proposal actually moves them out into the winter months, and does not affect the customer summer bills.

Next slide --

MS. HOGAN: I have a question.

MR. TRAINOR: I can take questions, sure.

JUDGE VAN ORT: How many people have questions on this?

MS. HOGAN: So, you know, our previous discussions really surrounded how PSEG Long Island is different than other utilities. My question is why is it necessary to try to line the customer charges like other utilities when we just discussed that there's a uniqueness in this situation, and the other thing that strikes me is while I appreciate you're trying to help those 450,000 customers, I think you call it balance billing, I'm assuming that's a budget billing structure, which is great. The one aspect about changing the inclining block, and having more of the cost recouped in the energy versus the customer charge, I think people would be more inclined to pursue energy efficiency measures if it was put on the energy and not on the customer charge, so I'm just wondering in your decision to pursue this approach, did you take into consideration some of those things? But I think the key question I'm asking is the customer charge, why do you have to mirror other utilities?

MR. TRAINOR: To start with the first premise was that we're different as a muni versus an IOU. To the extent that that is a total budget question, meaning that the presentation by Tom as far as the amount of money that we're collecting, that is correct, however, under the rate design aspect, the fact that the delivery rates collect the delivery cost of the utility, there is no difference between us and an IOU.

Now, are you asking us to the identification, have I done a fairness test on whether there should be in the energy or the customer charge, and my answer to that is, yes. What happens when you have a recovery system through rate design that is purely on energy, that energy charge is collecting fixed costs. Now, if you were to look at the cost that a utility incurs for a customer, those costs are relatively flat based on the size of a customer. If you were to look at the meter, it's about the same meter for all customers, the service line, the fact that we're meter reading that customer, the fact that we have a call center, that we have a function of mailing that customer a bill on a customer basis, those costs are all very flat regardless of the size of the customer. So, to the extent that you have a very small customer charge, and you have let's say $30 in costs that are incurred for every customer, there is a perception that the high usage customers are actually subsidizing the lower usage customers. That subsidy can be reduced by increasing the customer charge.

Now this is an intra-class cross subsidy, meaning that the resident and customers are helping the lower users. Now, in this case in my opinion, it is fair to raise the customer charge to collect those fixed costs through fixed charges, so that you reduce the intra-class cross subsidy.

MS. HOGAN: So, from a process perspective, Your Honor, this morning you had asked that we reach out and start getting information. I suspect I'll reach out to you, or somebody in my staff will reach out to you to try to get some of the information to formulate our testimony. Thank you.

JUDGE PHILIPS: Can I just ask that everyone who has a question on this section, if you could just sort of line up so that we can --

MR. GRAHAM: Joe, I know you've increased your fixed charges substantially, and I hear reason for that. You want to recover fixed cost or fixed charges, but when I look at the rate impacts, Joe, over the three years, I see residential service charges going from 10.95 a month to $20.18 a month, which is about an eighty-three percent increase. I see small commercial customers going from 10.95 a month to $43.80 a month, which is an increase of 300 percent over the three years. I see large commercial customers with customer charges going from $42.58 a month to $106.46 a month, that is a 150 percent increase. I see the demand charges for large commercial customers going up from anywhere between twenty-four and thirty-nine percent. I see the demand ratchet going up twenty-one percent.

My question to you, I guess, I know you referred to gradualism in your testimony, but I don't see it, how are you defining gradualism?

MR. TRAINOR: So, what you're saying is that the customer charge is going from 10 to 20. The proposal is actually that in the first year it go to 15 and 17.

MR. GRAHAM: I'm saying over the three years.

MR. TRAINOR: So, I'm presenting gradualism by not changing these rates all at once over three years. Again, I have been in cases where New York has approved customer charges at the $20 level, and I'm taking the customer charge up there. What I'm trying to quote as gradualism is over three years on steady steps.

MR. GRAHAM: I think that the Commission defines gradualism or defines the maximum rate impacts as twice the average. So, the Commission would say that an eight percent per annum increase in any fixed charge would be appropriate, not a 300 percent increase, not a 100-percent increase, not a 150 percent increase over three years.

The other thing I wanted to mention, now, you did say the other utilities have a minimum $15 up to $20. Is there anything about, you know, an investor-owned utility, we've mentioned our differences between an investor-owned utilities and the LIPA model, can you think of anything, any difference in the cost structures between the two that would say that LIPA wouldn't have a smaller customer charge than the typical investor-owned utility?

MR. TRAINOR: I'm sure someone can argue something, and this again as a rate design is an art, more than a science, so I can't say none. I wouldn't say that,I wouldn't get caught in that fashion, but the idea is that the models of debt service and amortization of costs really don't have anything to do with the recovery of the distribution costs which the customer charge collects. Again, the customer charge costs, the cost to send out a bill, the call center, those things have not changed via the fact that the model, whether it be a revenue requirement model or a muni model.

MR. GRAHAM: I was thinking more along the lines of possibly LIPA has lower debt because they are a municipality, they have securitized debt, securitized bonds, they don't pay federal income taxes, that kind of thing. I was thinking more about the levelization.

MR. TRAINOR: In the customer charge calculation, there is the recovery of a meter in a service, and in the recovery of the meter in service, there is a percentage for which you would apply into the current year, and what my marginal cost of service study does take that into account, and even on a marginal cost basis, the customer charge for which I'm requesting is still lower. So, even though there is a lower cost of debt, and I think that's your question, the customer charges for which I'm proposing is still within the cost of service answers that are produced by the marginal cost of service, accounting for your lower cost debt as a muni.

MR. GRAHAM: We have some issues between what you think are appropriate for meter and service charges, and what I think are appropriate.

Let me ask you this, you're proposing to eliminate the water and heating discount, that's a 400 kilowatt hour block that occurs after the first 400, in other words, the first 400 kilowatt hours is the standard rate, and then there's a water heating block that runs from 400 to 800 kilowatt hours a month, which is about 400 kilowatt hours for an electric water heater, and you're proposing to increase that by forty-five percent --

MR. TRAINOR: That's not correct.

MR. GRAHAM: Forty-two percent in the first year, forty-five percent over the three years.

MR. TRAINOR: The water heating current for the last thirty years, the water heating customers of the utility are paying the same rates as the --

MR. GRAHAM: I'm talking about the customers on rate 380.

MR. TRAINOR: Oh, I'm sorry, you're talking about the grandfathered customers. So, for the grandfathered clause, we're bringing them into the standard of the regular customers.

Again, for the last thirty years, there has been no water heating discount applied to the customers. We have a difference in rates between general and heating customers. What we don't have for the last thirty years, any difference between the cost of water heating and non-water heating customers.

MR. GRAHAM: But when you eliminate that discount for the 380 customers, that has an impact of about an additional $140 a year on those customers in increased revenues in addition to the service charges and everything else, correct?

MR. TRAINOR. I have not done the math. I have not seen your math, so I can't --

MR. GRAHAM: It's goes from about six-and-a-half cents up I think to ten cents, nine cents or ten cents, whatever you have times the 400 kilowatt hours. I'm just curious, did you look at who these customers are on the system, are these customers who are perhaps in retirement villages or anything like that?

MR. TRAINOR: There is about 5,000 customers for which we are discussing and after thirty years, there may be retirement communities, but it is more than likely, customers who have not changed their customer name, and it's the children of the original people that are in those houses, so is there any way to determine the difference between those, not unless you want to do a poll of those 5,000 customers, but again, in my opinion, after thirty years, it's probably the children of the original customers that haven't changed their account name.

MR. GRAHAM: Given that you want to eliminate this in one fell swoop, rather than using gradualism, would you agree that there might be a better way of doing that?

MR. TRAINOR: Rate design is an art. There's always a discussion asserted to that.

MR. GRAHAM: Thank you.

JUDGE PHILLIPS: Do you have other quesitons?

MR. GRAHAM: No. Thank you

JUDGE PHILLIPS: Can you just briefly identify your name for the transcript?

MR. GRAHAM: Hi, I'm Dave Graham, Department of Public Service.

MR. BROCKS: Your Honor, could we just have a moment?

JUDGE VAN ORT: Yes, if I could just ask one last question first. When was the last of cost of service study done that this comes from?

MR. TRAINOR: I would assume under LILCO.

JUDGE VAN ORT: The last cost of service study that was done --

MR. TRAINOR: That was presented publicly, it was under LILCO.

JUDGE VAN ORT: Okay. Thank you.

JUDGE PHILLIPS: Mr. Brocks, do you want to be on the record or off?

MR. BROCKS: Off the record.

JUDGE PHILLIPS: Can we go off the record for a moment?

(Whereupon, an off-the-record discussion was held.)

JUDGE PHILLIPS: We are back on the record. We just took a brief recess for the parties to, several of the parties to discuss, and also, for us to kind of discuss how to proceed. We're just getting a little bit concerned about the amount of time, so we've asked if the Company can basically go through the next set of slides that Mr. Trainor has, then take questions.

Also, we wanted to remind that this was intended to be an opportunity for clarification of the Company's proposal, but not necessarily the establishment of public parties' positions yet. You'll have the opportunity to do that in your testimony, so we would like to just maybe move forward, have Mr. Trainor finish, and then take questions.

The other thing, I guess we were going to poll is whether people could indicate which topics they had questions on, that might help us to kind of move to those areas a little quicker. So are there any other people who think they have questions on specific topics that they can identify at this time?

MR. GARVEY: Judge, my name is John Garvey. I'm from the DPS. I have a few questions relating to Utility 2.0 before you make your determination on the scoping issue. It won't take very long.

JUDGE PHILLIPS: Right, we are not going to make a determination today, but we'll listen to what is said at the technical conference that will inform the decision, and we'll take that under advisement.

MR. GARVEY: Okay.

JUDGE PHILLIPS: So if we could return to the presentation, and if you could go through the rest of your slides, and then we'll take questions, and move on to the next person, and we'll take questions.

MR. TRAINOR: Thank you.

I'm on the commercial slide for the commercial rate design. Again, here what I'm presenting is a removing of the seasonality of the commercial rates for which I'm presenting changes, which is small demand and non-demand customers. There is a multiple rate period class as well, but I'm not making those recommendations or changed those classes in any way at this time.

What I'm doing is trying to present a utility without seasonality in the delivery rates. Right now, we have a ratchet that is different in the summer versus the winter. I'm proposing to make that consistent throughout the year. We have different rates for the summer versus the winter, and I'm proposing to change that as well.

Now, the commercial classes also has a demand charge for the small non-demand, this is 7KW to 145KW. Right now the demand charge recovers about forty-five percent of the revenue requirement. Inclusive of the ratchet change, I am requesting that be increased to fifty percent of the revenue requirement. When I calculate the demand rate, it's actually a $2 increase in the demand rate, but again, you have to understand that these rates are recovering a total revenue requirement, and to increase the demand charge by more than the two percent or four percent, depending on how you want to look at it, the actual energy rates in these classes are going down. So, the increases that we are describing here are such that there was some big number for demand charge increase, that is not the total bill for which the customer is subject to. The customer is still subject to, by class, the four percent on average rate request because the energy component of the rate is actually going down. This is something that is a balancing effect between, yes, there is a large customer increase, but a customer charge on a commercial bill is a tiny percentage of its overall bill. So, yes, the percentage may sound very large, but on a dollar basis on the amount that that customer is paying, the customer charge is relatively small. It is paying much more in energy and demand charges than it is in the customer charge.

The premise here is forty percent demand charge to fifty percent of the revenue requirement being in the demand charge. That's a ten percent more in total bill basis. Again, there is a corresponding reduction in their energy component.

Now, this is a positive impact on not only the recovery of the cost throughout the year to again, align utility's fixed costs with the fixed cost recovery, but it also has the benefit of reducing intra-class cost subsidies, meaning that again, when energy rates are your primary vehicle for collecting energy and fixed cost, you have a disconnect between the amount that a person pays and the amount of cost of service of that customer. Again, there is a lot of commonality even in a commercial customers as far as the size, but how the load factor determines how much that customer pays. Increasing the fixed charges reduces the cost subsidies within the class, so that a higher load factor customer is not subsidizing a lower load factor customer for the same size, for the same output, for the same effort the utility is providing in servicing that customer.

The fuel and purchase power, the FPPCA, is taking care of the energy and capacity side. On the delivery side, all of those costs are fixed. Again, it's what determines the amount is the size, so the same size customer under an energy only rate design is going to pay more than a lower factor customer, and that intra-class subsidy is minimized by increasing fixed charges to recover fixed costs. And like I said there is no change to TOU rate designs at this time, multiple rate --

MR. WEISSMAN: We've spent a quite a bit of time on the DSA.

MR. TRAINOR: I'll skip the DSA, sure.

MR. WEISSMAN: If anyone doesn't have questions about it, we'll move on to the next slide.

MR. TRAINOR: The next slide I have is the gross receipts tax. Now, this is a minor, minor, minor issue asked specifically by the DPS, otherwise I wouldn't be bringing this up. Essentially, it's a cleaning up of a calculation that changed some portion of a customer's bill, essentially lower than one penny is transferred over to the commodity portion of the bill before a revenue tax is applied. Now, revenue taxes is a very small portion of the bill in total for the whole company is $37 million on a $3.7 billion budget. So it's a tiny number, and we're cleaning up the calculation of these revenue taxes, so that only the FPPCA is applied to a revenue tax calculation for the revenue side of the taxes collected for commodity, and only the delivery side of the person's rate is used to calculate the delivery portion of the customers' bills.

There is two separate rates for whether you pay for a commodity and delivery. There is currently some crosstalk between those two calculations, we're removing the crosstalk, so it's cleaner fuel for fuel, fuel rate, delivery for delivery, delivery rate. So that's really the only issue here.

The last slide here is reliability of data, and again, this is a question posed in the DPS comments. What we're providing is a cost of service study that is presented upon the 2016 budgeted amount. Those include the PSA detailed budgets on a FERC level to the extent that we were able to budget all of the PSEG costs on a FERC level. They're built into the cost of service model. The LIPA cost, however, are not done by FERC account, and they are done in major category, which are a debt service, A and G, and power costs. However, those fit nicely into FERC accounts, and are then allocated in such a way that they would be if they were in FERC accounts.

Now, plant data is not in the calculation of revenue requirements. There's no identification of return on plant. The plant in the cost of service study is just used for an allocation basis, so in that case, we don't have budgeted sixteen plant values in the case. We don't have the plants. We are using the best available plant data, which is the plant data as of 2013, scrub by the recent depreciation study.

So, the cost of service study does follow the cost of service principals that an IOU would follow. The cost, the detailed budget is by FERC account or simulated FERC account based on A and G, and power, and debt service. What I can present to you is that the cost of service study is not actually used in the rate request. It's not allocating the cost that we're asking each of the customer classes to recover. We're doing that on a pro-rata basis. So, the cost of service study has one purpose, which is to set customer charges, and to set demand charges. In most cases, the cost of service isn't setting the value, it's just used as a backstop or benchmark toward those values.

Now, in that light, if you turn to the next slide, one of the questions that I got was the customer charge, where do we stand as far as the customer charge. The cost of service study presents a customer charge north of $25. It's just the cost of the meter, the service to provide billing, provide meter reading services, the collections, the call center, that all costs the utility more than $25 per customer per month.

In recent history, the Public Service Commission has authorized customer charges that are much higher than we're actually proposing. We do have Central Hudson at 24, and Rochester at 21. We're over a couple of years going through the process of increasing our customer charge to what has been previously accepted by the DPS for other utilities.

Now, a quote that -- a question that I just got was that that's a very high increase, that's a big number, that's a big percentage. When you're just looking at the pure number, sure, it can be on a percentage basis, but that's not what customers see. What customers see is a rate request right now sitting at around $38. Now, $38 is $3.25 times 12 to get to the average customer four percent.

Now, if someone didn't have any usage at all, and it was always subject to the customer charge increase, it's shown that on the low point, that's going to be $60. So, that's the max-end of this consideration, but that's not the case. No one has no usage unless you're a vacant house. There is people with usage.

Now, the energy charge for the lowest building block that we have is essentially around $50 rate request, so that's $38 is the average four percent. The lowest usage customer that we're actually looking at that are probably mainly vacant houses or seasonal use houses, they're going to see a rate increase of about $50, this is $12 more on a yearly basis. So, you can throw out large percentages and any calculation that you like, but again, it boils down to $12 difference between a customer on an average usage at $38 versus a customer with a very, very, very low usage, just assuming a customer charge of $50. We are talking about a $12 difference. Now, you can do any math, and make any calculation or percentage that you would like, and that percentage is sure big whether it's fifty percent or one-hundred percent, but again, what it boils down to, and it's really just $12 on a residential bill that we're asking as the differential between a very, very low usage subject to just the customer charge increase that doesn't get the benefit of the energy charge going down. So, in that respect, the customer charge increase that we have, we're asking for in this rate request, just a flat energy charge, which is actually going to be lower in the summer than the current energy charge we have. I'm done here.

MR. WEISSMAN: We will, Your Honor, make these slides available on the website. I think if anybody has any further questions for Mr. Trainer on cost of service issues, rate design, I would request it be made now, and then we can move on to the next piece of presentation.

JUDGE PHILLIPS: That was basically your presentation up to page twenty-four? Because the following slides --

MR. WEISSMAN: The slides go from I guess twenty to twenty-four is similar to slide twenty-one. Different service.

JUDGE PHILLIPS: Does anyone have any questions, clarifying questions, on anything up to slide twenty-four? Okay.

Could you call your next presenter, please?

MR. WEISSMAN: I don't believe there was specific scoping questions on the power supply portion of the case, so obviously power supply is an issue we discussed today, and I've asked Mr. Napoli -- Mr. Napoli, he's our power supply witness to discuss how power supply is being addressed in the plan. He'll be able to answer questions on those issues.

MR. NAPOLI: Your Honor, what's shown up on the screen is really just three basic bullets for consideration of power supply.

One is in our baseline plan does meet -- was put together in consideration with the Federal State standard requirements, and the NYISO planning requirements for reliability, and it does preserve all the options in front of us for new energy resources and/or transmission projects that are currently under evaluation.

In the base rates, among other things, we do include the cost of Nat Grid PSA, which is different than the rest of the toll agreements that are in the pass-through rate, LIPA's share of Nine Mile point two, the capital O&M costs associated with that, and the cost for N-1-1 transmission projects, which we'll subject under the T and D discussion.

Our integrated resource plan, that I repose to work on, now that we have come to the conclusion that we're working under the NYISO planning criteria, we will take a more in-depth look at where we intend to go with the planning for Long Island. What that means in terms of the supply future, whether or not additional supplies will be needed in the future, when they will be needed, what type they will be, will replacements be needed, transmission, how energy renewables, energy efficiency renewables, storage, demand, on-site activities will implemented; all of that will be done within the confines of our Integrated Resource Plan, that we are looking to complete all of the base models by the end of this year, and then go forward with our public outreach and input to finalize scenarios and recommendations. That's basically all I have.

JUDGE PHILLIPS: Are there any clarifying questions? Is there anyone in the audience? Can you come to the podium? Just state your name.

MR. GARVEY: My name is John Garvey. I'm from the DPS.

Mr. Napoli, will you confirm whether or not the two projects that were previously discussed in the Utility 2.0

proceeding, the South Fork and the Far Rockaways projects are presently included in the capital budgets for the 2016, 2018 period?

MR. NAPOLI: Regarding the South Fork, we do not have a specific Utility 2.0 plan embedded within there, but we do within our FPPCA rate have cost or proxies for, what will ultimately be a solution, in other words, we have put in money to solve the potential shortfall on the eastern end of the Island. The ultimate solution of which is yet to be determined. So, it is in as a proxy of peaking units, but not with respect to that being the ultimate solution, and regarding the N-1-1 that which are the violations in the Far Rockaways and Glenwood, that is in the base rate delivery charge as under the exhibits from T and D.

MR. GARVEY: In terms of the South Fork, could you explain a little more how that's an actual line item within some testimony, is it in an exhibit in the rate case, or is that discussed in the testimony?

MR. NAPOLI: Yes, it actually is an exhibit. I'll actually have to look at the number for you, but it is in the exhibits.

MR. GARVEY: But to the extent in terms of the scoping issue to the extent that those two projects are already embedded in the rate case, we believe because that they will have a revenue requirements impact during that period, that we believe those two should continue to be discussed in the rate case, they are already included in the rate case.

JUDGE PHILLIPS: When you say those two projects, which, do they have names or are they --

MR. GARVEY: Do they have official names, Mr. Napoli?

MR. NAPOLI: I will defer to one of our T and D people speak, but there are specific designations for the N-1-1 projects in Glenwood and Far Rockaway, they are here today, so they can give you specific names.

And the South Fork, not a specific name. We have an issue with the South Fork, and what is embedded in the rates is an attempt to avoid a higher cost transmission solution.

MR. GARVEY: The only other project in Utility 2.0 that we believe should be in the rate case is their limit to AMI deployment, smart meter deployment. It is a limited deployment, and that's included in the capital budget of the rate case. The other programs from Utility 2.0, we don't believe will have a revenue requirements for the 2016, 2018 period, therefore, just those three projects we would like to include in the rate case.

JUDGE PHILLIPS: So, just to clarify, there's the AMI project, and then there are two N-1-1 transmission projects that will be named, hopefully, when someone else comes up?

MR. DAHL: Yes, I can name them right now.

JUDGE PHILLIPS: Oh, could you come to the mic, please?

MR. DAHL: It's Curt Dahl, manager of T and D planning.

Within Exhibit CBP 2, the very end of CBP 2 there, there's a line of N-1-1 projects. Underneath that line item is Valley Stream, East Garden City, New 138 KB cable, and Syosset Shore Road, new 138 KB cable, and phase in regulator, and those are the two projects which were being referred to here as N-1-1 that are in our base capital plan to address the N-1-1 limitations. Also, we'll be covering them later in the presentation.

JUDGE PHILLIPS: Thank you.

MR. KLIMBERG: Stanley Klimberg on behalf of Caithness Energy.

Mr. Napoli, could you tell us what opportunities will be available for the public to review and comment on the assumptions of methodology being employed in connection with the integrated resource plan?

MR. NAPOLI: Yes, currently we have and are continuing to develop on our website, information about the IRP process, and very shortly, the public input function will be active where we can receive comments indirectly.

As we work towards completing some base models for the end of this year, we intend to set up a number of public outreach sessions in consultation with LIPA and the DPS, and we will hold those to get that input to finalize that process during the first quarter of '16, so that we can form the final scenarios and recommendations to the LIPA cost.

MR. KLIMBERG: Will the public have an opportunity to review the assumptions and the methodology in order to be in a position to comment effectively on the assumptions and methodology, in order words, what will the process be? Will there be effectively a discovery process that will allow the public to become informed about the methodology and assumptions that are being considered, and to respond to them, and when might that occur?

MR. NAPOLI: Well, I think that's really -- that's beyond what we filed in the case here, and the case does not cover the IRP and its process, so we have to put that into our testimony, but regarding the process, when we come out and do those outreach sessions, yes, we will discuss what are the assumptions that went into each of the base models, and what the outcome of those were in order to allow people to be informed, and to ask appropriate questions.

MR. WEISSMAN: The IRP is a process that we're undertaking on behalf of LIPA. The process itself will ultimately be a run by and rules established, and rules made by LIPA; is that correct, Paul?

MR. NAPOLI: PSEG Long Island is running the process. LIPA will certainly review it, and we will go over it, and has oversight over the entire process.

MR. KLIMBERG: Previously there was an indication that the IRP process would be completed by December 2015. I think you just mentioned that it would be continuing into the first quarter of 2016, and based on that, could you lay out the timetable for the IRP process, and what you expect the Board's role to be, and when the Board might opin on the IRP plan that might be recommended by PSEG Long Island?

MR. NAPOLI: There may be some misconception when we say the end of 2015. We will have completed our work by the end of 2015 in order to hold public outreach sessions, have information, be able to share information and answer questions. We expect to complete all of that in the first quarter of 2016. At which time, we'll complete a final recommendation or recommendations that we will bring forward to LIPA's management, and follow the process that they lay out, which I believe will involve making a presentation to the LIPA Board of Trustees.

MR. KLIMBERG: In the event that PSEG Long Island were to recommended changes in the baseline power supply plan, or LIPA Board would decide to make changes in the baseline power supply plan, how might that be reflected in the rate plan in the event that there are revenue requirements that might attend, might arise from those recommendations of LIPA Board decisions; in other words, if either during 2016 to '18, or shortly thereafter, there were changes in the baseline plan that might require PSEG Long Island and LIPA to incur costs during the rate plan period, how might that be reflected in the delivery rates that are being proposed during the rate plan period?

MR. NAPOLI: Well, it's very hard for me to speculate as the outcome of what that will be, which is really what you're asking. Because I think the question will be the exact same as what would happen if the costs were far less than what you thought they were going to be.

MR. KLIMBERG: What is the mechanism, in other words? I realize you don't know what, at this point, what PSEG Long Island might recommend as a result of this comprehensive IRP process or indeed what the LIPA Board might determine, but what would the mechanism be for reflecting any potential increase in revenue requirements during the three-year rate plan period related to changes in the baseline power supply plan?

MR. NAPOLI: Well, if the changes you are saying are solely associated with power supply, and not, for instance, a transmission solution, which also could be the case, if they're solely for that power supply, the mechanism would be through the FPPCA rate.

MR. KLIMBERG: Changes in the cost of non-fuel related cost associated with the National Grid plans are reflected in delivery rates, Not the FPPCA; isn't that correct?

MR. NAPOLI: That's correct.

MR. KLIMBERG: So, changes in the National Grid arrangements could potentially affect the revenue requirements and the delivery rates during the rate plan if determinations were made during, as a result of the Integrated Resource Plan or other wise, that some of the plans, one or more of the plans, might be ramped out?

MR. NAPOLI: I don't know what your question is, I'm sorry. What is your question?

MR. KLIMBERG: The question is, isn't it correct that changes in the contractual arrangements for the National Grid plants under the Power Supply Agreement could affect the revenue requirements and delivery rates during the rate plan period?

MR. WEISSMAN: I believe that would be addressed -- I believe we addressed that through the DSA provisions, isn't that correct?

JUDGE PHILLIPS: Can I just jump in. I think, and correct me if I'm wrong, I think he's just trying to understand, is there a rate mechanism, proposal, charge, something in this rate filing that would reflect the kind of changes that he's concerned about during the period from 2016 to 2018?

MR. WEISSMAN: I believe the DSA provides for --

JUDGE PHILLIPS: So, the answer is, they believe the DSA will possibly have that affect; is that correct? I don't want to put words in anyone's mouth. Is that correct?

MR. WEISSMAN: That's correct, Your Honor.

MR. KLIMBERG: And the DSA is a proposal, so if the DSA is not approved or approved to cover power supply then the increased revenue requirements, if any, would have to be recovered otherwise?

MR. WEISSMAN: I believe that's correct.

MR. NAPOLI: Again, assuming there were increases.

JUDGE PHILLIPS: Okay. Thank you.

Are we moving on to slide twenty-six? Oh, I'm sorry, you have a question, clarifying question on the rate matter?

MR. BJURLOF: Yes, a question about process and where issues will be addressed.

The handling of capacity contracts clearly has a potentially major impact on things like Utility 2.0, and REV, and the advance of future of renewable energy. LIPA treats their contracts in a way, typically, fixed contracts, twenty year kind of commitments.

My question is whether the question about the capacity contracts will be discussed as part of this proceeding or whether it will be in the IRP, and if it's in the IRP, the question is whether you will have any access to that at an early stage like you have at this proceeding, or whether it will just be presented by the end of the year, here's what we're going to do, public comment, da da da (phonetic). So if you could clarify where the issues on capacity contracts will be addressed, I would appreciate it.

JUDGE PHILLIPS: I'm sorry. This actually sounds similar to what we were just discussing, and I think my takeaway was that the IRP is run by LIPA, I believe. Is your question different from the one that was just asked, you're asking about the IRP process?

MR. BJURLOF: I think this will effect the actual rate.

It's quite possible you have above it --

JUDGE PHILLIPS: I think that's a different question. Are you asking about the IRP process, or are you asking if what happens in the IRP process is going to be reflected in the rates that are a part of this rate matter?

MR. BJURLOF: I'm asking in which process, whether it's the IRP process or this process, that the impact and the capacity contracts will be discussed and dealt with.

MR. NAPOLI: I've also been joined here by my fellow panelist, Mr. Wittine, who is our manager of planning and analysis. But the contracts, as I mentioned before, all of the other tolling agreements of and within the PCA are within the FPPCA, and they will be addressed within that rate, and that's where your capacity and your fuel costs are right now.

MR. WEISSMAN: That is outside of the delivery rates that are being addressed in this case?

MR. NAPOLI: That's correct.

MR. KLIMBERG: Your Honor, Stan Klimberg again.

My understanding is that PSEG Long Island is going to be managing the IRP process, integrated resource planning process, and that at some point at the end of the process, there will be recommendation to the LIPA management and Board regarding resource planning requirements and strategies, and so, that was one clarification, I think if PSEG could confirm whether I'm correct in that regard?

MR. NAPOLI: That's correct.

JUDGE PHILLIPS: Right, we already covered that, I think.

MR. KLIMBERG: I thought you had, Your Honor, said something different, that's why.

JUDGE PHILLIPS: I hope not. That was not my intention.

MR. KLIMBERG: Could you explain what is the plan at the end of the PSEG recommendation regarding LIPA management and Board review on the results, is there a process that's been identified?

MR. WEISSMAN: Cause for speculate, but --

JUDGE PHILLIPS: Right. I don't know what else we can add to the discussion of the IRP process. I personally don't know about the IRP process. I don't think that that process is part of this rate matter. They already answered that they believe that any possible changes would be reflected in the DSA. I don't think there's much more that we can cover on that issue that pertains specifically to this rate matter, I don't think.

So, if you have a new question or a different question, that's fine, but I don't really want to cover ground that we've already covered.

MR. LAROE: Chris LaRoe of IPPNY. I just want to clarify if I'm in the right proceeding.

I know Utility 2.0 is on upcoming slides, so I don't have the benefit of seeing those slides ahead of time, so I'm not sure if I should wait or not, but one of the Utility 2.0

recommendations was a twenty megawatt solar PV expansion on the utility scale. Can you tell me if the current rate case counts for that in the baseline power supply, if it has a rate recover mechanism for that project? Would that be done pursuant to an IRP, or is there a third avenue for that project in advance that I am not aware of?

MR. NAPOLI: My understanding is all of the costs associated with Utility 2.0 are not in this proceeding, just as the impacts, if you will, of Utility 2.0 are not in this proceeding. If they're removed from the load energy forecast --

If the Utility 2.0 Program, as I understand, were included, the load and energy forecasts that's currently being utilized would be less than what it would otherwise be. That's why the N-1-1, Paul as well as Curt referred to, those costs or transmission system investments are included.

The other question another gentleman asked is, what about the local reliability issue on the east end that deals with transmission. Initially before the case was actually filed, the thought was is that certain features of Utility 2.0 would be assumed to be in place on the South Fork, which would allow for the deferral of transmission system investment.

When the decision was made to remove all the cost and/or related impacts or benefits for the Utility 2.0 from this case, we were then still at a situation where we were confronted with, here's a reliability issue that's local for the South Fork.

Because of the cost associated with the upgrades in the transmission system would be required, a decision was made as a proxy for the time being is to assume that several small combustion turbines are added to the east end in 2018 and 2019. The PPA costs associated with those combustion turbines are included in fuel and purchase power for the 2018 -- I know that the rate case ends in 2018, but they also carry on into 2019.

Those are intended to just solve for satisfying reliability, and the cost were intended to be a proxy. So, ultimately, a decision is made with respect to, you know, what is going to be the composition of Utility 2.0, and how rapidly, you know, will it in fact actually be implemented. If Utility 2.0 is approved, so to speak, and there are measures that can be put in place out on the South Fork, then obviously we would not be putting in a separate cycle CT zone.

MR. LAROE: I'm sorry, I guess maybe I missed it. How does that relate to the cost recovery for the twenty megawatts of solar PV, whether that be, whatever avenue that would be covered in?

MR. NAPOLI: To the extent that that program, that twenty megawatts of solar PV, was considered to be a Utility 2.0 Program in there.

If, in fact, we are talking about the installation of solar PV, I mean typically those costs are treated as costs of fuel and purchase power and recovered through the FPPCA, just like the FIT 1 and 2 Program.

MR. LAROE: I guess I'm still not sure if I'm in the right place or not.

MR. WEISSMAN: Perhaps, we can move to the next slide. The next slide covers Utility 2.0, and we have Mr. Volt here to speak to that as well. There's a slide in between on metrics but I'm wondering if Mr. Volt --

JUDGE PHILLIPS: Do you want to finish with Utility 2.0, is that what you're saying, you want to go out of order?

MR. WEISSMAN: Yes.

JUDGE PHILLIPS: That's fine with me.

MR. WEISSMAN: So, we'll go out of order, and also, I'm not sure if there are going to be any questions on the metrics presentation.

JUDGE PHILLIPS: Does anyone have questions on metrics? Okay.

We're going to maybe jump to Utility 2.0, slide 27.

MR. WEISSMAN: Again, Your Honor, I appreciate that, and just for the benefit of our metrics witness, we have included that in this presentation for completeness, but I'm not sure that in this technical conference there's a need to spend time. Maybe in the interest of time, it might be better served by moving forward to Utility 2.0 and ask Mr. Volt to --

MR. VOLT: Do you want to move it to slide 27 before I do 28?

MR. WEISSMAN: A brief touch on how we address Utility 2.0 in the case, and hopefully, this will set some of the ground work for, Your Honors. We were legally required under the Reform Act and under the OSA to make annual filings related to the energy efficiency generation, and advance grid programs. In so, I guess back in July of this year, and again in October, we made filings under those requirements to propose Utility 2.0 projects. Those programs are described in the rate plan, and we also describe in the rate plan, the LIPA Board of Directors approval of the 2015 operating budget amounts for Utility 2.0 Program development, and certainly, capital budget, and operating budget amounts for 2015.

However, we did not, because the Utility 2.0 Program has not yet been authorized beyond that amount, those projects were removed from the rate plan, the rate plan, the 2016 to 2018 period. We still strongly support those projects for 2016 to 2018 period. We believe they are in conformance with the State's Renewable Energy Vision, Reforming the Energy Vision, and that proceeding that's ongoing now, we're taking part in that, we're continuing to support these projects. But for the purposes of this rate case, at this time, those projects are not included.

I know people have questions for Mr. Volt, and we did include a slide here, the timeline for what we anticipate to be Utility 2.0, recognizing that these projects have not yet been approved, and Mr. Volt is here today to speak to that, and answer any questions regarding how we're handling those projects at this time.

MR. VOLT: Thank you, Pat.

So, as was stated earlier, none of these are in the rate case. We left these out, and basically, we don't have approval yet of our Utility 2.0 Plan. But what I wanted to lay out here for you is in January we got a preliminary recommendation from DPS Staff, and I've heard earlier today we may have more formal complete recommendation within a couple of weeks; but based upon the preliminary recommendation from DPS Staff, and what we believe to be projects that appear to be wanting to get more detailed RFPs out, so we can more detailed cost estimates on these programs. This is what the $2 million was for.

The development fund was to take some of these projects from concepts that we filed on October 6th, put more detail on them, get more detailed cost estimates, and then go back to the LIPA Board in a separate proceeding, and request for cost recovery at that time.

So, I just wanted to walk through the projects that we're moving forward with right now, and I say moving forward, but not implementing, but getting more detailed cost estimates, and getting more detailed designs. The three that are mentioned here, we call them load pocket initiatives. There's a South Fork which you have heard a lot about today, that's to avoid a transmission project.

We have an RFP that's being developed jointly with the Power Supply Group that will address the South Fork. The piece of it that's related to the energy efficiency demand response load control is a thirteen megawatt target that was filed in our October 6th plan.

Similarly, the Glenwood and the Far Rockaway load pockets, they're each addressing on the right side of this chart up above. They are each trying to adjust a twenty-five megawatt load reduction, which would reduce the amount that would otherwise be needed to meet the N-1-1 criteria. So, we have RFPs going out in both of those areas. About thirty days after we issued the RFP for the South Fork, we intend to issue two separate RFPs, or it could be combined, but one is going to be for Glenwood, and one's going to be for the Rockaways to look at all sorts of load reduction, demand response, load control techniques, which again would alleviate the peak load, and cause some relief on the N-1-1 solution.

The next one down here is the advanced metering initiative. We had filed back in July and then we updated it back in October to install essentially a communication backbone, which would be island wide throughout all of Long Island. We would have the capability of communicating remotely with our AMI metering network, and then we would also over a four-year period -- I just want to backup to the headline, it's '15 to '18, so this entire page is over the next four years. We wouldn't do this all at once, but beginning in 2015, there was some money approved by the LIPA Board subject to further review, they approved $3.9 million to do the communication backbone, and the first phase of these 50,000 AMI meters. Primarily, addressing the largest customer rate, 285 accounts.

Then there's the South Fork microgrid project. This is a situation again, on the same area in the South Fork where we have a significant load constraint and the high load growth area, PSEG proposed investing in a five megawatt, twenty-five megawatt hour battery storage project. We received bids yesterday from some consulting firms that are going to help us further develop that project, and again, we would go back to the LIPA Board, when we had the project fully developed, with cost estimates to construct and operate a battery storage project on the South Fork.

Lastly, the demand response initiative we had proposed. I think the number was $106 million over four years to reduce peak load by 125 megawatts, and this was cost effective. I want to point out too, all of these programs will only move forward if they're cost effective relative to other supply alternatives, and generally speaking, direct load control is less expensive than building peaking generators or transmission solutions. So, we proposed that in our October 6th filing, and as I said this whole page has not yet been approved by the LIPA staff, I am sorry, by the DPS staff, but we did get a preliminary recommendation from them, and we have been working every week. We have a call with LIPA and DPS Staff to go over these projects, try to refine them, and then ultimately, separate from the rate proceeding, we're moving forward.

So, with that, I'm available for questions.

JUDGE PHILLIPS: I actually have one clarifying question. I thought you just -- not you, the previous person said AMI was in the rate case.

MR. GARVEY: Let me clarify what I said. You actually said it correctly. If you look in the top row of the three projects to the right, the South Fork, Glenwood, and Rockaways. Mr. Napoli indicated there are cost proxies in the capital budgets for these three projects.

Now, when they say that Utility 2.0 is not included, they mean the alternative to those cost proxies are not included in the capital budget.

JUDGE PHILLIPS: I'm not asking about that, I'm only asking about the AMI. I thought, just a little while ago, I apologize, I am not good with names, I thought it was stated that AMI was in.

MR. GARVEY: I did state that, and I believe there is approximately $21 million in the rate case for AMI deployment.

MR. VOLT: I can clarify that. In July of last year, we filed this AMI infrastructure, which was to install the communication network, and then also to install 50,000 AMI meters. That was approved as 3.9 million for the first phase of that in 2015, which is prior to the rate case being started. Assuming that we move forward and we construct that communication network this year in 2015, the capital budget included $7 million per year for 2016, 2017, and 2018 for AMI enhancements to expand, but that was not the same as this initial AMI deployment, it was an expansion of it.

JUDGE PHILLIPS: Okay. Thank you.

MR. WEISSMAN: Is that expansion part of the Utility 2.0?

MR. VOLT: It's not part of Utility 2.0. It's part of the capital budget.

MR. WEISSMAN: Right, and Mr. Eichhorn is here to speak to that later in the presentation.

MR. GARVEY: Just to reiterate DPS Staff's position, is that we believe the three projects on the first row, in addition to AMI deployment generally, should be addressed in this rate case.

JUDGE PHILLIPS: Okay. We got that. Thank you.

Does anyone else have any clarifying questions on the slide that was just covered?

Who's responsible for the next set of slides?

MR. WEISSMAN: Next slide, Your Honor, is just a brief discussion of Long Island Choice, which I'll present. I think we had discussion of this this morning.

We are proposing in the case no changes to the Long Island Choice Program at this time. Particularly in the context of this rate case, there is the pending IRP that's ongoing, a capacity market study, and there's separate department review that's been suggested to go to Long Island Choice. There are still substantial fixed power costs that will remain in the delivery rates for the Nat Grid PSA, and Nine Mile Point 2 costs incurred by the company will continue to focus on being compliant with the REV process and other New York utility choice programs, but it may not be possible. There are many, many issues with regard to retail choice on Long Island that really need to be addressed. We agree with the recommendation made by DPS staff and I think that was concurred by the ESCOs that a separate track for the consideration of Long Island Choice is warranted.

I think these kind of questions cut across the testimonies and the expertise of a couple of our different witnesses, Mr. Trainor, Mr. Napoli, and I would request that in the context of this technical conference that if there are any additional questions with regard to that, those questions be directed to those witnesses, and we'll see if we can move forward.

JUDGE PHILLIPS: Before we go there though, I thought the position this morning was to sever the Long Island Choice issues from the case?

MR. WEISSMAN: That's correct, Your Honor, we agree with

DPS Staff and the ESCOs in their scoping documents to sever and consider Long Island Choice issues in a separate proceeding.

JUDGE PHILLIPS: Are there any parties here that have a different position on that, who wanted to ask questions about Long Island Choice, New York City? Let's go off the record for a second.

(Whereupon, an off-the-record discussion was held.)

(Whereupon, a brief recess was taken.)

JUDGE PHILLIPS: Let's go back on the record. We are going to continue with -- which slide are we going to continue with?

MR. WEISSMAN: We're on slide 30, Your Honor, it's consumer outreach. One of the issues that the DPS requested we address in the technical conference was our resourses for consumer outreach, and we've asked Mr. Dan Eichhorn, who is VP for customer service, and one of the witnessess in the case to speak to that issue raised by DPS.

MR. EICHHORN: Thank you, Matt. Good afternoon, everybody.

One of the things that we recognize at PSEG Long Island is the importance of communicating with customers and keeping them up-to-date as to what we're doing, what new services we have, what new enhancements, and also reaching out to them to get their input, and to what is it that customers are looking for.

In fact, one of our most important metrics that we have, it's one of the heaviest weighted metrics is our J.D. Power customer satisfaction score, and if you look at J.D. Power, J.D. Power provides us with tons of information, and one of the things that is very evident in J.D. Power scores is, the more a customer can recall communications from the company, the more satisfied they are. Likewise, the more a customer gets involved and takes action, so if they participate in something like balance billing, or paperless billing, or they get involved with an energy efficiency initiative, the more actions that they actually take with the company, the more likely they are highly satisfied, and that's something that we really take near and dear.

We know also during storms, communications is neck and neck with actually doing the restoration. So, most customers know we're not going to be perfect, but they don't accept that we can't communicate to them and at least give them an idea on what's going on. So, a lot of our plans that we implemented in 2014, and the things we're looking to do through the rate case years is really to enhance the communications, the outreach, the engagement that we provide with our customers.

On that slide is a listing of the different mediums that we use to communicate with customers. It's approximately twenty different ways. What we're really trying to do is reach customers of all ages, of all types. We have customers who still operate and work in the cash society, and they like to deal with us face-to-face in customer offices, and we opened two new customer offices in 2014 to meet the demands of that customer group.

We also have a newer generation, people who are much more online, much more self-service. One of the things we did in 2014 was replaced our automated phone system in the call center, and we've had a lot of success with customers increase in their activity in that. We've reduced a customers' wait time to do a transaction in the automated system. So, you can see the various methods that we have for communicating with customers.

One thing that is up there too, is a community partner program. Just to give you a feel for that, what we're doing is using our employees, a lot of it on their own time as a volunteer effort, to go out into communities and get involved and give customers presentations as to energy efficiency, electric safety, understanding your bill, ways to pay your bill, ways to communicate with us. That's a program where we're getting people in the company to go out, and if they're involved in a church group, a social organization, a sporting club, possibly a rotary club, anybody that would really want to understand energy efficiency, electrical safety, or just what is our general plan in the company.

We're planning to do hundreds of these meetings a year, and we have it as an initiative for all of our managers to get their employees involved. Part of that is, our employees are super dedicated and super confident, and we know that they're leaders in different organizations that they are involved in outside of work, and we know that if they communicate a message to a friend or relative, it's like a trusted source communicating that word. That is something that we feel is unique. We have shared that at other industry conferences, and we get a lot of attention from that by trying to leverage our employees and their relationship in their community to bring the message and the things that we offer out to customers, as well as a lot of the traditional things that you can see on this slide that we do.

As far as the scope of our outreach, I'd really like to break it up into about five major segments. Outreach for our low income customers, outreach for education, storm communications, our government communications, and in more of our corporate and media communications. And I'll just say a quick word or two about each of those major categories.

So, in the area of low income customers, we try to reach our low income customers through a couple different means. One of the big ways is through bill inserts, through direct mailers, but another way that we really try to leverage getting to low income customers is through the various states and local agencies that deal with low income customers. We did have a low income conference or fair, you can call it, where we invited a lot of those organizations in. So, if the organizations who are dealing with low income customers, if they know what's available through the utility, they can pass that on to customers when they're dealing with them in various social services that people get involved with.

In the education area, what we try to educate customers on, one is their consumer rights. We're always trying to educate customers on electrical safety. We do that just about every time we see a storm rolling in, and give customers reminders about wires down, stay away from them, call us, regardless of whether they think it's a telephone, cable, or electric wire.

A lot of our communications are around energy efficiency, how can customers save money on their bill, and that's one thing that we really want to focus on in the rate cases. One of the biggest drivers of a customers' monthly amount that they pay is their usage, a two percent or four percent increase in their bill. If customers really get engaged with energy efficiency, it will far offset two or four percent. So, the thing that customers can do to reduce their bill, the greatest, is right in their control by using their usage, monitoring it, and doing some things that are good just practices in general, and that's something we really want to key on in the next few years.

Another thing that we try to educate customers on is a lot of our offerings and our enhancements. As I mentioned, customers tend to have much greater satisfaction, the more they're engaged and the more they're interacting with us, so customers need to know that a week ago we just made it available that they can pay by credit card. We'll have some informational campaigns that will start next week to let them know about that.

We have made changes to our balance billing program, so that it stabilizes the balance billing. We've also made changes to our paperless billing enhancement where on a customers' bill, they'll get a due date and the amount due right in the e-mail they get every month. So, we're really making business a lot easier for them to do business with us.

We have a series of enhancements. We have a five year technology plan that we really think will benefit customers in the way we communicate with them, the way we outreach them, and the way they communicate with us. We've looked across all industries, and there's some really great things that airlines are starting to do with when a customer calls you from a smart phone, the phone system will recognize it's a smart phone, and it'll push an app out to that customer's phone. It'll allow the customer rather than talk voice to navigate through the automated phone system on their smart phone. So it's things that airlines are doing now. They're all the types of things that we are looking. Those are the type of things that we want to implement over the next few years, and that's part of the reason why we have an increase in our rate case for improvements and opportunities in outreach in our customer service.

When you look at the offerings that we have now, they're probably about what a company would offer ten to fifteen years ago, very little state of the art, really technology that would wow a customer that would really meet the needs of some of these emerging customers that are coming into the workplace, and into ownership of phones, and being our customers.

The other major thing we focus on is storm communications. We have an entire storm communications organization, which is made up of seven directors. So, when we see a storm coming and we go into storm mode, every director in customer services, as well as our government affairs and our corporate communications, has a separate storm role, and a separate team, and everybody has a role. We've really beefed up those communications, and we want to take it to the next step. So, some of the thing that we want to implement going forward is better communications with municipalities. We've implemented this year something called a Municipal Portal where villages and towns can log directly into, not our management system, but a portal, and they can tell us what critical facilities they have out, and they can tell us if there's a roadblock because there is a wire down, they need somebody to come out and identify whether that wire is live, make it safe, whatever we need to do. So, we want to take that to the next level.

That was really in the accomodation of government communications and storm communications -- as well as government communications, one of the areas that we focus on is really trying to do outreach, so that when we have a large project that we're doing public meetings, we're meeting with township officials, meeting with government officials, and really laying the ground work out, so that people know we might be coming out, might be working in the street, might have to disturb some areas, and give people's thoughts, ideas and work together with the towns and villages.

In the fifth area, as far as our scope of outreach is really in the corporate communications and the media. There we really looking at doing press releases, communicating openly transparently with the media, and really try to provide information out there. Another thing in that area is social media. We really try to leverage our involvement in social media. So, we have a Facebook page, we have a Twitter, and other utilities, especially our New Jersey utility, has seen a lot of success, especially in storms, putting information out in a social media area where it can be shared with many people even if you don't have a lot of social media followers. Those are some of the things we've worked on as well as the website, and our outage maps and outage notifications.

We've covered a lot of stuff on this slide, and I touched on some of it as we went through, so really what we think in 2014, we have done a much better job, and we have a very good comprehensive outreach and communication plan to customers. As I've mentioned, we have a whole bunch of things that we're looking to change over the next five years, from technology to processes and enhancements that we want to make for customers, and we really think it's critical that we get that word out to customers so they know what's available in the realm of efficiency, they know what enhancements we've made, and what things they can participate with us. That was all I had.

JUDGE PHILLIPS: Does anyone have any clarifying questions on what was just presented? Okay. Could you tell us what your next slide will be?

MR. WEISSMAN: DPS also asked that we address our AMI strategy. I think Mr. Garvey, who put that question out there, and I believe we have Rick Walden, who is going to come up and speak about our AMI strategy. This is outside Utility 2.0.

JUDGE PHILLIPS: We have one question about outreach. Could you come to the microphone?

MS. LUFT: Irene Luft from the Department of Public Service.

What is your definition of a low income customer?

MR. NAPOLI: The definition of our low income customers are that they are in some other program that establishes them as low income. The primary one is heat, but we also have veterans that are disabled, we have social security. We have a whole list of various departments, but again, the Utility doesn't classify a customers' low income. We rely on a third-party to identify them as low income. They need to apply to that every year for us to consider them low income, so they must be in heat, and they need to apply for that every year, as an example.

MS. LUFT: I have another question about a community partnership program that you mentioned, what kind of incentives do you give these employees? I'm not sure if you said volunteer or --

MR. EICHHORN: The way we work our community partner program, it's a combination of meetings that we do after hours, and some meetings that we do during hours. Some of it is going and visiting schools and giving safety programs to kids, and some of it is meeting with local fire departments and giving them updates. We ran a program on solar safety for fire departments, so if they go into a house with solar panels, they have certain things they have to be aware of.

The programs that we do during the day are typically run either by our management folks or our union folks. The programs we do at night are typically run by management. We don't give any direct incentives out, so we're not telling people if you do five programs a year, you know, we're going to give you some kind of reward. It's something we've identified as an activity that supports the end goal, which is to improve our customer satisfaction, improve the perception, get the word out of the things that we're doing, and it drives some of the customer satisfaction goals that we have. So there's no direct incentives related to that program.

MS. LUFT: So, if it's after hours, there's no overtime involved?

A. There's no overtime for management employees. If a

Union associate attends something after hours, we're obligated by labor laws to pay them, so what we try to do is keep our Union associates focussed on programs during the day that would normally be paid, and then cover the after-hour programs with management, and there's no pay for the management associates who attend them.

MS. LUFT: Thank you.

MR. WALDEN: I'm Rick Walden. I'm going to cover a couple of slides on our AMI strategy.

On the first slide, I would like to highlight as sort of the high level objective of our strategy, and maybe just touch on a few of our current capabilities. We have no plans to install a full scale AMI deployment, but we are planning to leverage the considerable amount of work that's been done at our company since 2007 on AMI programs, and really it's designed to improve customer satisfaction, to improve our operational efficiency, and really to provide a platform for future visions without full scale deployment.

In terms of the current AMI capabilities, we have about 7,700 meters deployed on the island. They're concentrated in pockets based on previous pilots since 2007. One of the primary given focuses of any AMI program is to do automated meter reading. We have an exceptional performing program. We read about 99.7 percent of all the meters every day. In fact, many of them we read every fifteen minutes. We have every single type of meter on the system. We can read the meter and produce a bill for every tier of customer, residential and commercial.

On Fire Island, after Superstorm Sandy, we replaced all the metering on Fire Island with AMI, and all of those meters have been equipped with remote disconnect switches, so we've been able to improve that technology. We also have web presentment capabilities for anybody with AMI data. We basically take the data that was read yesterday, we send it through our reader data management system, and present it on the web to customers, and they can view their daily consumption, they also get tips, frequently asked questions, and can provide feedback. They basically can learn how to interpret their energy consumption information and make better decisions on how they consume their energy more efficiency.

I'm not an electrical engineer, so I won't get into the algorithm of how AMI does this. We measure voltage and current and power factor in it supports identification of tampering. The last point that I'll make on this slide is, as I said it earlier, we have a network that's deployed. In an AMI system, you need to have a communications network, and the meters actually communicate to the network, and then the network communicates back to the utility. So, that network is deployed in pockets, as I mentioned earlier, so that limits the ability to put more AMI meters out across the Island, so we would have to expand the network in order to have further reach.

Next slide. Let me talk about the future in terms of future deployments and what's planned. Just segueing from the point I just made, we want to increase the network, the communications backbone, if you will, across the entire Island, Nassau and Suffolk Counties completely. That would enable us to strategically deploy AMI as we want to across the Island at any time, and it supports what's proposed in the rate case. We plan to deploy the communications network in 2015.

As far as the rate case specifically, they're really -- I classify the deployments in the rate case under two broad headings. The first is just adopting a policy of AMI metering just as a course of action for all new meters installed. All new meters would be AMI meters. We would have the AMI communications network installed in 2015, so those new meters when they got installed beginning in 2016, they would connect to the network instead of being, for a typical residential customer, instead of being read every other month, they will be read at least every day, so estimated bills would be history. Under that policy we would install about 40,000 residential meters per year, and approximately 5,000 to 10,000 commercial meters a year.

The second broad category for expansion would be what I call saturation expansion. In contrast to the policy expansion, which would be sort of random, as new customers come along, wherever they're located, they would get a new meter. If you had a problem with a meter, that would get replaced, that would be random in nature. Saturation deployment would be specifically designed to address either specific problems or specific geographic areas. We have a safety problem, a customer with a bad dog, we have customers that are chronically unable to access, so we estimate them time and time again where we would deploy new meters. A whole new neighborhood goes in, they would all get AMI meters, or we want to do a whole route. We want to eliminate a whole route of meters or a whole circuit, that would be a saturation deployment.

So, the primary benefits of saturation, you really get enough critical mass to sort of cash the check, if you will, and realize the O and M savings, or to get real benefits O and M, safety, etcetera. So, we're looking at about 6,000 to 10,000 meters a year for that type of a deployment.

So, I thought it might be helpful if you go to the next slide to just get a visual of what does this look like, what does the future look like at the end of this rate case period for the number of meters that would be affected. We have approximately 1.1 million meters, so at the end of the 2018 period by the adoption of these deployments, we would have approximately thirty percent of our commercial accounts completed, and we would have about fifteen percent of our residential accounts completed.

So, with the commercial accounts, just some of the outcomes that I would expect as a result of this, and there are many others, but I just hit some of the highlights, O and M savings, long term estimates would go away, billing exceptions. A lot of these commercial accounts, especially the large ones, are hard to get to. They have a lot of billing exemptions because they're manually read, and there are numerous components that meter readers have to read, and if they make a mistake, it kicks out. We would have fifteen percent of our residential customers whose meters are currently read every other month, their bi-monthly meter reading would go away. Those customers would have an actual monthly meter reading, no estimates. We would address on safe conditions, as I just mentioned. Putting meters in with accounts with dogs with rear property access, etcetera. Web presentment of energy data would be available to nearly 200,000 customers. All 178,000 customers, all of them would be eligible to review their energy information online.

One of the real benefits here, we have a robust solar program that's ongoing, as you all know. Besides improving the customer billing accounts associated with those accounts, which are many, it would support system planning and operations. The meter that is on those accounts right now is a net meter, so you can't really tell how much energy was generated versus consumed, it calculates the net, so we really need that information for the T and D folks. They know better than I what they need for that, but that would be helpful to them.

Lastly, another example, we would eliminate some of the old legacy systems. We have a system that's called MV-90, that's a dial-up system where we access approximately 1,500 of our largest accounts, and they would be eliminated. We would eliminate the people that support that in the back office, the vendor support, and besides those accounts are fairly unreliable. They're accessed by plain old telephone lines, pots lines, or cellular modems, and both of those are not as reliable as the new technology, so those are a few of the highlights of our strategy.

I'll be happy to take questions.

MR. BJURLOF: Just a quick question, what is the -- I assume a wireless communication structure that you're using for that. What is the communication infrastructure, and what's the cost of that, and have you made an assessment of security concerns that are involved.

MR. WALDEN: Communications really has two parts. There's approximately a 900 megahertz frequency RF communication between the meters. They talk to themselves, and they hop to the nearest meters, and then they communicate to a device called a collector, and those collectors communicate back to the utility using cellular communications like a Verizon backhaul.

The cost of our communications network is approximately $1.6 million. It's actually -- Long Island is ideal for this type of technology. It's very flat, it has high density. It's about $1.6 million.

MR. BJURLOF: So, this is a wireless 900 megahertz, Verizon is what you're using actually?

MR. WALDEN: Well, the 900 megahertz is the AMI vendor's communication and that's fairly standard in the industry. The backhaul is wireless communication.

MR. BJURLOF: Have you looked at other technology since there is free -- wi-fi, for example, can be done securely that would have no cost?

MR. WALDEN: Well, we are actually looking at our own fiber network at our Utility, so that's something we're looking at as well, so it would be private.

MR. BJURLOF: I was talking about wireless.

MR. WALDEN: Well, we're so early in the process that new technology we're looking at constantly.

MR. FRODO: Joe Frodo of Suffolk County.

We have been having a number of billing issues with PSEG that we are currently working out. One of the things that we're doing to overcome some of those issues is to have AMIs installed on our largest billing accounts, but it doesn't seem that customers who have these meters installed will have the option of being on a monthly, calendar month meter reading schedule, and I just want to clarify if that might be possible because it takes out of question a lot of the variable rates that are blended, like your power supply charge, the demand delivery charge that's proposed, is it possible for customers who get these meters to go on a calendar month reading cycle to better manage their cash flow?

MR. WALDEN: Absolutely, I don't know see why that would be a problem at all. We just did Stony Brook University here in Suffolk County. They had approximately one-hundred meters, and they were having problems with a lot of estimated reads with what's the normal schedule, and we converted all of those to AMI metering.

MR. FRODO: That's good to hear.

Another question relates to energy efficiency projects and your revenue decoupling mechanism and how this tool might better serve ratepayers on those two issues as opposed to calculating energy savings based on energy efficiency improvements that have been done. Are you planning on using these meters to actually measure and verify the success of energy efficiency upgrades? I mean when you replace a light bulb, it's easy to calculate over so many hours what your energy use reduction should be, but when you install motors, or heating and cooling equipment, those systems rarely perform as they are calculated to perform if they're not properly maintained, so if you employed this technology to provide incentive based, performance based incentives, then when a project is installed and properly maintained over a success of years, you're better assured of gaining those efficiency reductions in demand that we're calculating now but may not be actually achieving.

MR. WALDEN: In our AMI Program that we currently have, we have what's called a Meter to Day Management System. All of what's called load profile data that is read from meters is actually stored there. That information is available for analysts to compare through the M and V, through our energy efficiency programs. I'm not the right person to ask if that's what the plan is for energy efficiency programs, I will tell you that we have the technology to support that. Our system has been in place for several years, and it's integrated into our customer information system, and it is a system of record for the interval data that is there, and it's available for access to do those types of analysis.

MR. FRODO: That's good to know. I would like to suggest that you could better protect rate payers' investments in these programs by utilizing that technology to spot check projects and the various programs that are going to be offered, so that you know if your calculated savings are matching up with your achieved savings.

MR. WALDEN: Yes. Thank you.

MS. LUFT: When these AMI meters are installed, will customers be able to opt in or opt out?

MR. WALDEN: That's interesting. We have had approximately one-hundred customers that have reached out to us, and told us they wanted to opt out, but none of them had AMI meters. We have not had a single customer that has AMI who has elected to opt out. I believe our stance is that if somebody doesn't want an AMI meter, they don't have to have them. But I will tell you the more people that get on board with an AMI system, it makes the network more robust and dependable.

MR. PAMERIKI: Dan Pameriki (phonetic) of DPS.

Two questions, being that these meters, the AMIs are read in realtime, are you going to give customers the option of what their billing cycle will be, or will it be on their present billing cycle?

MR. WALDEN: Well, since I run the manual metering operation, when people go on to AMI, it shouldn't be any problem. It might take a little work on the back end in billing, so I don't want to speak for billing, but I know that other utilities have offered that, and I don't think if that was important, I don't think it's an unsurmountable problem. It's an IT issue, but I don't think that's going to be a big problem.

MR. PAMERIKI: Secondary question, as you're projecting as you can see thirty percent commercial accounts, fifteen percent residential, is the company looking at a corresponding decrease in physical fuel personnel to read these meters?

MR. WALDEN: Basically, we have an aging workforce, like everybody looks like me or maybe close in age, so naturally part of the strategy is to be able to position the company to be able to take advantage of attrition, and that would be my hope, is that we would not have any layoffs, that we would be able to use attrition to cash the checks, if you will, for a business case.

JUDGE VAN ORT: I just have one question. Can you give us a sense of when you're doing the replacement meters, you mentioned new neighborhoods, new circuits, things like that, but how many of these meters are being replaced, you're replacing meters that are at or near the end of their useful life?

MR. WALDEN: I don't know that off the top of my head. We do replace, or we touch approximately 30,000 to 35,000 meters a year that are either a new installation or replacing an old one. We go out, and we have a selectives program, or periodic test program where we go out and take a sample of meters, and we test them for accuracy. If they fail, we go out and we, over some period of time, replace all the meters in that family that failed maybe over one or two years or so. But I don't know for this specific question.

In my past, I would say that the average life of a utility meter of the old vintage, the one with the dials, which they don't make anymore, is about thirty years. Any new meter that is digital has a life of about fifteen years typically. In my past in metering with other companies, on average, the average population of meters out there is about half of its useful life, but I don't know what is at LIPA offhand.

JUDGE VAN ORT: Mr. Weissman.

MR. WEISSMAN: DPS also specifically asked about the status of certain underperforming renewable and energy efficiency programs, and I think Mr. Volt is going to briefly speak to that. It's in this slide, and I'm sure he can walk through it, or if anyone has any questions on it.

MR. VOLT: So, we're on three programs that are based on our Opinion Dynamics. We have a third-party evaluation consultant every year. Opinion Dynamics has been that consultant for the past several years, and they look at things like you just heard from one of the questions, what the actual savings are, and they try to measure the actual savings for the programs, and they compare that to the cost of the programs. Then they come up with a benefit cost ratio.

Where it says PA ratio, that stands for the Program Administrator Test. It's basically, the benefits of the equation is all the avoided costs of capacity and energy that are saved over the life of the program, which is typically about fifteen years, and then that benefit is divided by the costs of the program that was spent to achieve it.

We've rated the programs out of a total of fifteen programs. There are three there. In 2013, this was the result of the 2013. This report came out in May 2014, and these three programs failed the benefit cost test of less than one.

So, the question was why would we continue, and I just wanted to discuss, so the REAP stands for Residential Energy Efficiency Partnership, and that program is for low income customers, as we heard earlier the definition of low income customers. Low income programs are typical in the industry to not pass the benefit cost test, but they're done for other reasons. It's done because it's a needy population. It's done for reasons beyond simply saving capacity and energy.

So, in this program, we go into homes or qualified income eligible homes, and we typically will replace any incandescent light bulbs that we find. If their refrigerator is older than a certain vintage, we'll replace their refrigerator, and in recent years, we have added room air conditioners and dehumidifiers. We think that addition of room air conditioners and dehumidifiers will help increase the benefit cost ratio because we get summer peak reduction for a relatively low cost, at least compared to a refrigerator, a room air conditioner, a dehumidifier, is a lower cost. So, while we think that those changes that we've made to the program, and we show now that it went from .4 up to .8 benefit cost ratio, it's still less than one, but we still recommend continuing this program because it's a population that we feel is underserved, and can use the assistance in this case, new refrigerators or air conditioners and lights.

The next two in both cases we have discontinued these programs, the Solar Hot Water Program and the Backyard Wind Program. Neither of which were large programs. They've both had a very small number of participants. I think the Backyard

Wind was about fifteen or so over the past four years, and the Solar Hot Water wasn't that much more, so they were very small programs. The costs that we spent on those programs, the benefits did not outweigh the costs, so we discontinued the other two programs. With that, if there are any questions, I am available.

JUDGE PHILLIPS: Are there any questions? Okay. Can we continue?

MR. WEISSMAN: DPS has also asked us for our strategies for mitigating the concerns about load pocket issues that can strain transmission capability. We've touched on a lot of these issues I think earlier today through Mr. Dahl and I've asked Nick Lizanich to join us. They are both witnesses in our capital budget testimony, and they'll try to walk through these as quickly as possible, and see if there is any remaining questions after this morning's -- or the earlier discussions today.

MR. LIZANICH: Thank you. I will start us off and being the last speaker, I'm sure there is a lot of people very interested in us trying to get through this in a timely fashion and I'll try my best.

So, the first topic is on load pocket mitigation and strategies that we have in place concerning how we take the need for expanding the transmission system and evaluate other alternatives that could be very much in play. In the last year, of course, with the filing of the Utility 2.0 documentation, and the REV proceedings that have taken on since that point in time, we have adjusted, expanded, if you will, our analysis for transmission system expansions for utility system expansions. It's not just the transmission solution. It's T as well as D. We have expanded our alternatives to include the evaluations of what we would call nontraditional solutions, that is opportunities to be able to look for something that may be not the normal kind of thing, you know, the hard wire type of solution.

We still hold true to the reliability requirements that we have in terms of us needing to provide the N-1 capability that both the NYISO as well as our own internal planning standards dictate, but we are testing the markets to determine whether there are some competitive opportunities where others can come in and help us develop a nontraditional solution to be able to provide that in a cost effective manner, such that we would be able to take an otherwise normal routine, T and D hard wire type of expansion system, and turn it into an alternative. In the past, we relied upon things like the energy efficiency renewable programs, so what we're talking about here is something above and beyond what would have been part of the traditional evaluations.

There were three RFPs for major load areas and five smaller ones, and I've asked Curt Dahl to join us up here, join me at the podium here to talk a little bit about those particular RFPs and what they will do.

Now, keep in mind, this is not part of the rate case proceedings, but it does tie into some of the questions that we have had earlier, and some of these projects and these RFP areas, you will recognize because several previous speakers have already referenced these particular pockets of opportunity. So with that, Curt.

MR. DAHL: Thank you, Nick.

So, towards that end, as Nick mentioned, we're going to be issuing three major RFPs for load pocket constraints that we see on the horizon over the next five years, getting into the details on the following slide for those pockets. Those are each some of the largest -- we'll go right to that.

The poster child of REV and Utility 2.0 design here, the South Fork, this area is about 300 megawatts in size. It's growing at a rate of about three percent per year, roughly about ten megawatts. We hit the first constraint we see in 2017, and using conventional T and D solutions, we've identified over the longer term out through 2022, a $294 million transmission investment requirement. So, that allows quite a hurdle there for Utility 2.0 and REV type investments to be considered. So, we are looking through that RFP for REV solutions that could potentially be brought to bear to relieve this area.

This would compliment existing resource injections that are currently under way. We have, going back even before the REV and Utility 2.0 came in vogue, going back about two years ago when LIPA put forth its FIT Program, we have deployed resources in a way that we try to identify or consider locational constraints, and avoid T and D benefits. That was certainly the basis for the forty megawatt Solar FIT Two Program that LIPA put out roughly about two years ago, and at that point, they had incent of that program with a very substantial of seven cents per kilowatt hour premium. Unfortunately, we were only able to get about 21.3 megawatts of response out of that program, which at a coincident 5:00 to 6:00 p.m. peak load contribution only amounts to about seven megawatts. So, like I said earlier, we're growing about ten megawatts a year.

We will also be looking for in the 2017, 2018 timeframe, thirteen megawatts of guaranteed DLC, a load relief program, to compliment that solar to get us at least through the year 2019 with some REV like considerations.

By the year 2019, we hope to again, bear the fruits of our REV RFP, that we're developing right now internally, but it's still under development so I don't want to get into too many details on that, but it will be performance based, it will be technology neutral, or a technology agnostic. It's not going to call for any type of specific technology. It will be performance based where we'll say we need this many megawatts for this many hours. We've targeted primarily at Montauk and East Hampton locations and satisfying the long-term needs of that area. It will include a microgrid option or concept, and at this point again, we don't want to discount any technologies by making a requirement either.

Lastly, we will have a battery as kind of a backstop and be there to address the intermittency associated with renewable technologies.

Next slide, again, two other load pockets. I mentioned earlier that we have three load pockets with significant T and D investments. South Fork totalled about $200 million. As a result of the 2014 nerve implementing of bright line standard for compliance with NERC standards, bright line being 100 KV and us having a very substantial 130 KV System on Long Island, we fall under mandatory and forceable liability standards of the NERC. About 113 new standards, which we need to comply with covering all aspects of operations, planning, education management, etcetera.

One of the standards, TPL standards, has affected our compliance with two of the pockets, mainly the Rockaway and Glenwood. We have a requirement within the next two years to identify a plan to satisfy the needs for these pockets, and we have seven years to actually install a corrective solution, which takes us out to about 2020, so it tends to dictate the timing by 2020. We do need to have a solution in place to be compliant under NERC standard.

Using conventional transmission solution, we've identified in the Far Rockaway pocket, the need for about $130 million conventional transmission solution, which again is highlighted in the rate case CPB 2 that we talked about earlier. Glenwood is about $170 million transmission investment necessary to address that N-1-1 consideration, which we need to comply with. So, in response to that, we again have considered -- we are putting out alternate RFPs for REV like solutions in these two pockets, initially targeting twenty-seven megawatts load relief in Rockaway pocket and twenty-five megawatts of load relief in the Glenwood pocket.

MR. LIZANICH: So, beyond those three major areas of potential opportunity for REV type solutions, PSEG Long Island has put together a five-year capital plan for the investments on the T and D system of which 2016, 2017, 2018 are part of this rate case proceeding. Associated with that was a screen process to look at the capital investments that we are about to make in various parts of the system, and we had identified these five, we'll call it a smaller regional opportunities, where, you know, the initial screening done internally, we are not convinced that there is an opportunity that we can see, but we looked at as an opportunity. As an opportunity to be able to take these five examples here, and I'll ask Curt to briefly walk through them, but take an opportunity to look at these, put out an RFI into the industry for people that are in that space to be able to develop solutions, and help us identify what could be a fix in a

Utility 2.0 opportunity.

Now, keep in mind, our capital plan has these five projects in them. Our rate case is based upon these projects, but this RFI is happening in parallel with that, so if that there is in deed an opportunity in any one or more of those, we would investigate that and look at it from an economic perspective to determine whether this made sense for us. So, with that, Curt, can you walk us through?

MR. DAHL: So, the Kings Highway project is roughly a $28 million project, solving load relief project, at multiple locations including Central Islip, Hauppauge, Smithtown, and Indian Point substations.

To allow for deferral of this project, we would need to basically have thirty-eight megawatts of DLC brought to bear at five substations and seven different feeders to relieve the constraints that this substation in lieu would have relieved.

This project also has an added reliability feature that it resolves an N-1-1 issue at the Hauppauge industrial park, which is the second largest industrial park in the country, and the Kings Highway substation would relieve that. To address that reliability issue, we would need another twenty-five megawatts, so in total we would need sixty-three megawatts, which represents about thirty percent of the area load in terms of DLC to address the deferral of this project.

Navy Road is roughly a $10 million substation project.

Immediately, we do need to resolve a one to two megawatt overload, which are only ten percent of the peak output over those two feeders. There is a transmission aged infrastructure there. The substation was built in 1930. There's also a flooding issue, but we could address the immediate thermal need with the DLC solution equalling one to two megawatts.

Hempstead is an $18 million project that would address -- this is the only twenty-three KV substation that we have in Nassau County, so we would like to upgrade this to sixty-nine KV, but if we did receive six megawatts of load growth, we could defer this $18 million project.

Similarly, Eastport and Plainview, they're both $18 million projects as well. They have comparable load reduction requirements. The Riverhead, Easport, if you reduce six to ten megawatts through DLC, which represents about twenty percent of the Moriches and Eastport substation load, we can defer that project.

Lastly, Plainview, Ruland, that's associated with some large dump loads we have coming in. At Canon, Wang is proposing a development at Country Point at Plainview development as well as supreme manufacturing plants coming in that would put pressure on this line, and we would need a twenty megawatt deferral, or twenty megawatt DLC contribution to defer this project.

MR. LIZANICH: Thank you, Curt.

The last slide on this topic, just is here as an opportunity to be able to talk a little bit about the things we've done that impact generation, the transmission system modifications, the things that we have been able to do involving generation on the Island.

I'll skip the last item that we just talked about, the Utility 2.0 opportunities in South Fork, Far Rockaway, and Glenwood. But the other ones up there are very notable in that over the last several years, we have made investments, LIPA has made investments in the system to install dynamic reactive devices out on the east end at Holtsville and Wildwood. What those do is they provide us the ability to solve system problems in lieu of having to put on additional generation on the east end, as well as expending the transmission system. So, these devices, there's three of them now on the system, the Holtsville, Wildwood, and the one previously installed to Canal substation. These are opportunities that we have taken advantage of in the past in lieu of expanding transmission or expanding the generation on the east end.

Then the topical items sort of ran us in reverse, but we have currently a couple of projects underway that are looking at minimizing the much spread generation that we have on the Island, and looking at some very great paybacks for us from a transmission perspective of, you know, expanding Holbrook to put in a double bus tie (phonetic) in to alleviate a significant amount of high cost generation on the Island, and there are several other examples as well that will help us reduce costs to customers in terms of the power supply charges. So there is quite a bit of activity going on in that space.

With that, I'll pause for questions on this topic before I move to the next one. These projects are in the final. These are part of four capital expenditure plan.

Any questions? I'll take that as a no. Judges? Okay. I'll proceed.

There was also a question that was asked to us that talked a little bit about -- relative to why is load growth cited as a Capex driver, that was a question asked of us. When then in reality when you look at the rate case submittal, we talk about the system growing at .1 percent, net the demand side management program. In reality, and I'll try to explain this in a few minutes here, but the reality is the system is actually growing at about two percent per year. And that two percent per year is a gross number because with demand site management programs, that load growth does come down to the .1 percent. So, when you think about the two percent that's happening out there, Mike Volt had spoke earlier about the renewable energy efficiency type of programs that we have in place, we are able to reduce the net load growth on the system from two percent down to .1 percent.

Bet let's talk about the two percent and what that means because we could talk about how we look to reduce the net load growth on the system, but the reality is there's things happening on the system that we have to pay attention to. When we talk about a two percent growth rate, it really comes in a couple of different ways. There's what I will call the incremental growth at customers. Let's face it, somebody probably just went to Best Buy and bought another television or something, and that's an incremental growth to us.

But then there's also developments that take place on the Island. An expansion of a customer facility or a new facility being built, and we'll talk about a few those as examples to give a sense of the kinds of things that we're dealing with. So, you have pockets of the system that are growing. You have discrete load additions. Garvies Point is one of the examples --

Let's go to the next slide. I'm sorry. Garvies Point is a great example. This is up on the North Shore but it's a development being talked about, a two to ten megawatts in size. Two to ten, what does that mean? Well, it starts small and then it will grow over time. We have to plan for that. We have to respond to what I will call discrete load additions. At Flowerfield we have had ongoing discussions with Stony Brook University about the expansion of their tech park, and the new 200,000 square foot facility that they want to build there. That's a discrete load addition. I could go on. There's a whole example. Some of these are very notable. You've probably heard about many of these. The Nassau Coliseum, it's the last year for the Islanders to play. They're going to turn it into a different kind of use, involving the Coliseum, but a lot of extra opportunities there. Well, that turns into discrete load that we have to address.

There are several other examples that are more long-term in terms of us looking at it. The Heartland Town Square development is a great example that where Wycoff and his development company is looking at doing a major, major development in and around the Pilgrim Hospital area. Something that's not on my list, but something that turns into twenty or thirty megawatts. So, what happens is -- many examples that I can go through but I will avoid, but what happens is you get these discrete load pockets that grow, customers expanding, and it's not just the big twenty, thirty megawatt size, but it's also the small incremental loads of the K-Mart being built down the street, or the new gas station, or what have you. So, you have these discrete growths that take place, despite the fact that overall in the system we're growing at two percent net the .1 percent. So, there are pockets of the system that are growing much greater than that, so if we said that the system is grow at two percent, there could be pockets growing, I have an example up there, the east end of Long Island is actually growing at three percent. I could talk about various other specific pockets of the system that are growing potentially even higher than three percent.

When you look at our system in general, when you look at the loading of our substations, and our transmission system, and our distribution system, we add capacity in discreet blocks. We don't have the ability to infinitely control, adding one megawatt or two megawatts or three megawatts, we add them in an economic fashion where we have a standardized design and we add blocks of capacity in that manner. So, what ends up happening is we get to the points where some of these pockets run out of capacity, and for the developments that are planned, for the developments that are actually underway, or have already taken place, we end up with pockets of load growth that we have to address, hence a five-year plan is developed where many of the things that I speak about, for example, the development of the Heartland area. These are opportunities that are coming. We don't know the timing of them. We do our best to anticipate and develop and build a plan around those.

So, therefore when we talk about it, if I could go to the next slide. Obviously, changes in building codes has a huge impact. We're right across the street almost from the Hauppauge industrial area, and there's an ordinance pass that's actually going to allow them to expand upwards. I just met with the town supervisor of Islip the other day. We were talking about the -- there is a south end part of that that comes into the Town of

Islip. We were talking about what that has in terms of impact, and the opportunity for those tenants of that park to be able to expand upwards. Outwards is a little bit tough because we are almost to the point of being landlocked, but upwards is an opportunity. In fact, they just put new sewage systems into the park. The sky's the limit, if you will, and that I believe they are up to six stories is the new ordinance. So, the opportunity there for customers to grow. These become localized issues that we have to address in our planning that goes forward.

Ironically, Kings Highway substation that we just mentioned a few moments ago is an expansion in and around the Hauppauge area. So, as growth in that park continues, that's why Kings Highway is there, for not only the park, but for the surrounding areas as well. So, this is all part of the plan that we developed. This is all part of the growth.

So, as I said, you know, we've actually in the case of the east end have challenged in the past, the energy efficiency renewable folks to help us reduce that growth rate down to a more controllable, from a infrastructure perspective and that's the working relationship we have in place. That's why in the exampled I offered earlier about the five small regional opportunities for possible Utility 2.0 slash REV solutions, that's why we do that. We look for those opportunities, identifying those as opportunity areas for us that we would otherwise spend transmission investment, if not for an alternative solution.

With that, I will take any questions related to load growth.

MR. GRAHAM: Hi, Dave Graham of Department of Public Service.

I just want to ask, the load growth you're talking about, is that summer load growth?

MR. LIZANICH: Yes.

MR. GRAHAM: So, when you're designing the system, you're designing to meet the summer peak, right?

MR. LIZANICH: We actually design to meet both summer and winter peaks. In most cases on Long Island, the summer peak is going the trump the winter peak loads.

MR. GRAHAM: Thank you.

MS. KLAT: Hi, Alisha Klat.

I had a quick question about the Glenwood facility that you're talking about. Have you factored in the new transmission lines that have just been put up last year in the Town of North Hempstead with respect to the five megawatts of growth, and I think you said $177 million for the cost of that project?

MR. LIZANICH: The answer to that is yes, but we're talking about two different things here. The lines that were constructed in that area last year dealt with load within that pocket and the ability to serve into the pocket, when Curt had explained earlier about the Glenwood area and the opportunity for growth. That's a larger area than the specific problem that we were solving in and around Bar Beach and Port Washington. Curt, do you want to expand on that?

MR. DAHL: Yes, the load pocket constraint, the project you're referring to is a 69 KV project. The load pocket constraint is actually a 130 KV project feeding into the greater load pocket, which covers -- it starts with the 138 KV system and works its way down to a 69 KV, so it's a specific new standard that we need to design for where we need to be able to operate having one line out of service and then absorb the loss of another line. So, it's a new standard, that 138 KV, like I said the bright line is imposed. A bright line definition, anything above a 100 KV has to meet that double contingency standard now and that's the basis for this new project.

MS. KLAT: So, that would be in the Glenwood Landing facility location now, that's being revitalized, so to speak?

MR. DAHL: So, there's a place holder project in CPB 2 that we talked about --

MS. KLAT: I'm sorry, I don't know what CPB is.

MR. DAHL: That's the exhibit, the company to capital budget testimony for the rate case, and that was the Syosset Shore Road Project. So, it goes from Syosset to Glenwood and Shore Road. It's synonymous.

MS. KLAT: And that's not going to be offset by any sustainable energy projects?

MR. DAHL: Well, we are putting out an RFP to see what kind of alternative solutions exist with regard to the DLC and other resources. Mike and I had also mentioned that. So, we are going to see if there is a cost effective alternative solution that could satisfy that need.

MS. KLAT: Okay. Thank you. Your Honor, I had a question, but it wasn't addressed in any of the previous presentations. It was regarding vegetation management and tree trimming. I wondered if it was possible to ask that as a general question, and I also had a question about the budget as a whole, the proposed budge as a whole?

JUDGE VAN ORT: How much more do you have on your slides with these fellows?

MR. WEISSMAN: Just one more topic that we will address on the Sandy work and the FEMA grant.

JUDGE VAN ORT: Do you have someone here who can speak to the tree trimming?

MR. DAHL: I'll answer those questions. Let me hear the question and I'll see if I can answer it.

MS. KLAT: That would be great. It seems like in the testimony and on the budgets that I read that it'll be an increase you're proposing for a $42 million budget for vegetation management Island wide with approximately ten full-time employees on staff overseeing that. A $42 million expenditure, and the remaining aside from what they are utilizing, the remaining amount would be going to either consultants or subcontractors, and I wondered if you could speak more about that? It seems likes it's an incredible increase and there's not a lot of granular detail with respect to that line item. And I wondered if there was something that the public would be able to review as well with respect to this issue?

MR. DAHL: So, let me just take a stab. If this isn't going to be an adequate response, we'll take an action to do a follow-up on it.

MS. KLAT: It'll be included in the scope?

MR. WEISSMAN: There's been a lot of discovery in the case on vegetation management information being provided. Again, we tried to prepare for this technical conference by looking at the scoping items that were raised. Vegetation management, although addressed in a lot of questions that we're getting and we're trying to get answers out to, was not.

JUDGE PHILLIPS: Can I just ask is this one of those things that you can maybe try your best to answer, and if you don't have the right people here, perhaps, is there a way maybe to answer it on your web page or some other way?

MR. WEISSMAN: Are you representing a party in the case?

MS. KLAT: No, I'm not.

JUDGE PHILLIPS: What I'm wondering is if you could add it maybe to like an FAQ or something like that? Only if you can't answer it here, I think that may be a better way to do it because she's not representing a party.

MR. LIZANICH: Let me take a stab. I'm the director of asset management. One of my peers in the organization actually runs the Vegetation Management Program. When you speak about consultants, let me try to explain how tree trimming is performed. So, internally we have on staff line clearance inspectors, supervisors, people who oversee that operation of clearing the lines. So, when you talk about additional people coming in to help get over this larger expenditure that we're planning, they're really providing oversight over top of contractors. We do not trim our own trees. So, when you spoke about consultants those are actually line clearance contractors that we hire, and they provide the service to us of trimming to our spec, and providing that service.

In the rate case and the budget that we prepared, there is an increase in tree trimming costs because our goal is to get to a more four-year cycle of trimming as to opposed to what was the previous year. We're trimming to a larger box, providing a greater separation of the wires to the trees that will remain, so there is an increase in that expense. The plan over time will be we will have an increase in costs to get through the first cycle. We call it a cycle. After four years, we'll be on the second cycle, once we get to the four-year period. So, what happens is you have a large investment to cut a lot of the wood out, and create the corridors, and then you come back for a lesser cost over time. It will take us years to get there, but over time then you'll have a lower cost of having to maintain those corridors. So it's contractors that I think you referred to, where all the money is going, it's going to the contractors. There's a large expense for that. We have some 150-plus line clearance contractor employees that are actually here trimming our trees on our behalf. And that's about as far as I'll take it. Beyond that, I would just ask --

MR. PAPPUS: I'll add on to that.

MR. DAHL: I'll introduce Ted. He's one of my peers as well. He's the Director of Operations.

MR. PAPPUS: Good afternoon, Ted Pappus, senior management T and D operations. I've been responsible for at least putting together a number of responses to DPS inquiries, so I read enough about vegetation management that I can try to muddle my way through here.

One of the things that went on in '14 and '15, due to the freeze in rates, there was no increase in tree trim of vegetation management in order to get it up to this four-year cycle. So, what's going to happen starting in 2016 is a little bit of catch-up because they reviewed what was being done. They concluded what they wanted to do, and they want to go to this four-year cycle as an accrued utility practice, trimming the trees every four years. So, there's going to be an up-tick in tree trim cost over the life of the rate plan. Once everything is back on a four-year cycle, which I think it should be by the end of the rate plan, then they expect a downward trend in tree trimming because you have now cut these corridors around these wires, and why do the trees still grow, once you've had these larger corridors, they feel you can go into a less trim every year. So, it's going to be a four-year cycle, but the hypotheses is that because everything has been trimmed adequately now, the amount of wood you will have to take off every four years will be less.

So, up-tick in costs, get to that four-year cycle, and then decrease in cost.

MS. KLAT: What's the projection of the decrease in costs?

MR. PAPPUS: Offhand, I don't know.

MS. KLAT: Because I noticed it steadily increases year after year.

MR. PAPPUS: It steadily increases and then they expect -- I think you probably don't see it in this rate plan because by the time they get onto the full four-year cycle, it will either be in the last year of this rate plan or the following year. It's approximately a $10 million reduction starting in 2018.

MS. KLAT: It just seems that there's a large expense, a blank line item in writing, I know that we are on the record here, but to the extent of there could be more clarity with respect to those expenses?

MR. PAPPUS: I think if you look at the written testimony --

MS. KLAT: I did.

MR. PAPPUS: It talks about this increase and there are a number of DPS inquiries regarding this that should be coming out very shortly, so we can respond to that.

MS. KLAT: I'll give you an example of the reason why I'm here speaking is because just on Court Boulevard, we have trees that were pruned beyond repair. They're not according to your standards, and these contractors are not being overseen by your ten people. Within the same year, they have pruned that same exact strip, so it begs the question that there's this broad leverage out there that these contractors -- it's just, I guess it reminds me of the days of roar, so you want to make certain that there's some oversight respectively, so I'll look forward to seeing that, more information on that.

MR. WEISSMAN: You named a particular street that you're concerned about?

MS. KLAT: I used that as an example, right.

MR. WEISSMAN: I think we'll be happy to talk to you offline.

MS. KLAT: That's a separate issue. I don't think that's really a part of the rate case per se. I'm bringing it up as an example of contractors going unchecked with respect to tree trimming.

MR. WEISSMAN: Again, there are many interrogatories of discovery request, most by DPS Staff on the tree trimming program that have been answered, and are being continued to be answered. We'll be happy to talk to you offline about those.

MS. KLAT: And my last question is, is there a place for the general public to review the budget in a user friendly format?

MR. WEISSMAN: The rate case is available on the PSEG Long Island website. It's readily accessible. I think it's on the home page of the PSEG Long Island. It's one of the major sections, I think on the middle right-hand side of the page. It talks about the rate filing. From there, it's a couple clicks to get to all of the testimony and exhibits that have been filed in the case, and beyond that, there's additional information, frequently asked questions. There's an opportunity for you to put your own comments into the company to the rate case as well on that website. Frankly, to me this is the easiest way to get it. I think the filing is also available on the DPS website. The discovery responses and things like that are really made available to parties in the case. I'm not sure what other kinds of information that you are looking for.

MS. KLAT: Simplified numbers that the general public could understand and look at, and say, oh, I understand why the LIPA and PSEG is asking for an increase in their rates.

MR. WEISSMAN: Well, we'll have to refer to Mr. Harrington for that.

MS. KLAT: Well, good thing he's here.

MR. WEISSMAN: Again, I think if you're looking at the testimony itself -- your point is the testimony is --

MS. KLAT: My point is that nothing is user friendly. I think that for the general public to have an understanding of what is going on with respect to this rate case, that some type of clear, either graphic bulletpoint chart, something to that respect would be helpful, so that there could be meaningful commentary. This is a challenging forum. I took a day off from work in order to be able to speak to you with no lunch at 3:40, so I know that the DPS has put forth many opportunities for the general public to speak.

I'm questioning the availability and the type of quality of the material that's being proffered by LIPA and PSEG.

MR. WEISSMAN: We do have public statement hearings. There was one last night and there's one tonight in this room, where we will be giving which I would consider a higher level discussion of the rate filing. Again, it will be going on and the Administrative Law Judges will be here to take public comment. There will be an information session prior to that, I believe it beings at 6:00 tonight, Your Honors?

JUDGE PHILLIPS: Yes, the public forum begins at 6:00 and the public statement hearing begins at 7:00 again in this room.

MR. WEISSMAN: I know you've taken time already, but it might be a more user friendly, if you will, opportunity to hear about the case, but we're available to talk to you at any time.

MS. KLAT: I appreciate that, okay, thank you.

MR. LIZANICH: Are there any other questions, if not, I'll move on to the last topic.

JUDGE PHILLIPS: Are you going to be covering slides 44 through 47, I guess?

MR. LIZANICH: We just covered 44 through 46. We are now on 47. One of the questions that was asked of us was to spend a little bit of time about the Sandy damage that occurred, and the actual steps that are underway both within the rate filing as well as other funding sources. This graphic that I put up on the screen is just to point to the fact that Sandy pretty much affected everybody on Long Island. We had some one-million-plus customers out of just over 1.1 million customer base. Pretty much everyone was impacted in some way.

You will notice there is some white on this. One of the whites is the Peconic Bay, you can't count that. One of the whites is the Great South Bay, can't count that. One of those is Brookhaven National Lab. You sort of get the idea that it's pretty much something that impacted pretty much all aspects of the LIPA service territory.

I'm going to talk about two pieces to this. If you go to the next slide, we're going to talk about flooding. So, you know, there was really two wars that we fought. The first war was the wind and the damage associated with the hurricane coming, and the impacts of it, and then the second was the flooding associated with the high tides and the surge that came in, and affected Long Island customers, specifically those on the south shore.

This was a graphic that I think, Mark, you had this in the newspapers, so if I owe you credit, I'll thank you for providing it. If you look at this graphic here, it actually gave a sense of what levels of surge were across the Island, and, you know, in my next slide, we will talke about where we actually undertook damage. It's pretty hard to read, but I'll read them for you. Down in Atlantic Beach, we had some 12.7 foot surge. We had some seventeen foot surge on Long Beach, and then similarly in Port Jefferson, about an 8.7 surge. Clearly, as you got into the New York harbor, you know, that's where the surge was greatest. For the New York City folks represented, I apologize because this graph does not show the Rockaways. This was a Long Island and came out of the Newsday newspaper, but frankly, it got worse as we got into the Rockaways.

Another way of it, that I'll look at this is really in the next slide, and this is what happened, we had some twelve substations that got severely impacted by the flood damage. If you all remember, there was three tidal surges that we all faced. The first, the second, and finally the third. The levels of flooding that we took on was really something that was as expected on the first surge, and as we expected on the second surge, and come the third surge where we learned was that the receding of the water from the second surge never took place, hence three came on top of two and that's in a nutshell what resulted in us having some severe damage in our substations as well as the hundreds of thousands of residents of both Nassau, Suffolk, as well as the Rockaways being impacted by this flood damage.

This listing here is of the substations. There are twelve of them listed. Our action plans going forward are to repair and rebuild ten of these. We actually are taking the opportunity to retire two of these older stations, so then the Neponsit substation, which is out on the Rockaway Beach down towards Breezy Point, and then Atlantic Beach, which is on the west end of Long Beach Island, those two are being retired, have been retired, and have been replaced with capacity at adjacent stations.

So, as you look at this, in the Rockaway Peninsula, there was specifically four stations that had impact, and recognize that Far Rockaway substation serves not only the Rockaways, but also comes into the southwestern part of Nassau County.

So, efforts are underway to rebuild the substations. Now, this has been ongoing since Sandy, so for two years now, we have been at this. What we are doing is all of the gear within our stations are being replaced. Anything that was damaged in Sandy, immediately after the flooding, we went in and did some cobbling together, if you will, cleaning as best we could, to put the power back on for the customers recognizing saltwater contamination is something that's never going go away, and we continue to do a high level of maintenance on those substations to be able to keep that salt contaminant from coming back in.

We're in the process of replacing. Now, it's not as easy to say to every customer, give us six months, and we'll turn the power off, and we'll rebuild everything, and we'll put you back on when we're done. So, it's a process by which one station gets done, the next one, the next one, the next one. They're done serially because of the capacity, we have to serve the customer load. We are partway through, I would say we are probably over halfway through this effort, at least on the Rockaway Peninsula into the southern Nassau County, but we have a lot of work to do. It is represented in the capital budget in the rate case. There's a continuation of a lot of this rebuilding of substations, replacing switch gear, replacing control houses, battery systems, and all of those things inside those stations, so that we can get it back to a pre-Sandy condition. This takes time.

Now, we have done some temporary measures at these stations to prevent further water intrusion. The worst case scenario for us was to have ourselves halfway through the rebuild, and have another hurricane come that just sets us back further, so we did some temporary measures.

One of the key aspects to this is the elevation of the gear. In Queens, as well as the New York City and Metropolitan area of the boroughs, as well as down the Jersey Coast, new flood maps were created. So, we're utilizing those new flood maps. We are elevating to a point on the flood maps per the code, we've elevated. If you looked at Arverne substation today down in the Rockaways, you'll see it's some six feet off the ground, and that's because we've experienced some five feet of flood waters into that station, and we have taken steps to be able to further prevent, the other being the worst case event, which would be a similar event of even greater magnitude of what Sandy was.

This is in process. If you were to look at the projects that we've identified in the capital plan, you will see many of these stations repeating themselves, a switch gear on the distribution side of that station, and a switch gear on the transmission side of the station. As I've said, it's a couple more years of effort to get to the end point on this.

One of the opportunities that we're faced with is LIPA has been awarded a grant of some $729 million associated with mitigation of that T and D system. Ninety percent of those dollars will come from the Federal Government. I think that was mentioned earlier in one of the testimonies provided.

There's really four tranches to this grant. The first being the elevating of substations. Now, it's only a $9 million portionment of that grant, but that's because this is only for the incremental raising of a piece of gear, you know, the cost of putting in a foundation at grade, the cost of putting the elevation at six feet off the ground. There's an incremental cost there, and that's what FEMA will pay for. So, the first is to address those substations that took on damage, and that work is underway, and is continuing at this immediate point in time.

The second tranche of a much smaller is tranche than the others is a $5 million component of the grant associated with transmission lines. The reality was during Sandy, we did not have a lot of transmission system damage. It was minor and we did have some cases, so the grant money is dedicated towards those circuits that were damaged to do things to harden them up, to put higher strength poles, reinforce the crossings of the LIE, and the parkways, and the railroad, so that when, God forbid a wire deos comes down, it doesn't impact the movement of people and emergency services across the Island. So, that's our general theme to how we will portion those dollars, but that has not started at this point in time.

The third tranche is associated with sectionalizers. Now, very simply, a sectionalizer is a device when there is a fault, these devices can be operated remotely, so that if a circuit was to trip off and affect maybe 2,000 customers, to pick a number, the sectionalizers are designed such that half of those customers come back on immediately within seconds, within minutes. Therefore, the impact of the outages is a lot more concentrated to the area where the pocket truly was damaged. FEMA sees this as a great opportunity, and has toward us about a $75 million tranche for basically doubling the amount of automation that is currently on the distribution system from some 1,350 existing devices to something double that. That would give us the opportunity to further allow the isolation of the grid into smaller components, such that for a line fault, more customers will be able to be restored automatically and very quickly as opposed to those that would be unfortunately waiting for the repair truck to come and make the repairs.

The final tranche, and really the largest of the tranche, and if you remember the slide earlier where I showed the red on Long Island, is going to be the rebuilding of the main line distribution circuits. Now, we talked about circuits, we have some 1,000 of them on Long Island. We talked about circuits that are in the overhead. We have some, let's just say 900 circuits. We have identified and prioritized the worst performers, based on Sandy, based on Irene, based on all the major storms that we have had on the Island. By counting the number of customers that have been interrupted, we have actually created a prioritization list of the circuits, so the worst performing circuits will get the first crack at the dollars associated with this $640 million tranche expense.

FEMA anticipates that if we were to go back and build overhead, reconstruct overhead lines, we would rebuild some 1,000 circuit miles. That's a great opportunity for us to rebuild a lage portion of the main line, which is from the substation out to the customers to rebuild those main lines to be able to minimize the number of future consequences that we would have on those lines. Right now, that work is being staged.

We are in the process of bringing in the contract community to help assist us in the deployment of all of these tranches of this grant, and we have actually just recently received approvals to start the first couple of circuits. So, in the next month or so, we will begin to do an outreach to communities to be able to let them know that we're coming their way, and we're going to begin this process of rebuilding and hardening up this distribution system like LIPA has never seen before.

So, with that, I'll take any questions on the FEMA grant.

JUDGE PHILLIPS: Are there any questions?

MR. GOODMAN: Thank you for the information. I have some very specific involved questions just to clarify.

At one point you mentioned -- I apologize. I don't remember the location, but you mentioned one elevation project where at the location, there was I believe five feet of flooding you said, and the elevation lifted the equipment to six feet, so as I understand it, that foot of increment in elevation is what I have heard referred to freeboard, are you familiar with the concept of freeboard?

MR. LIZANICH: I am not familiar with the concept but I understand the premise behind with which you're going with that.

MR. GOODMAN: Who decided that a foot was enough as opposed to three or five?

MR. LIZANICH: It's really much more scientific than just we took Sandy and added a foot. We didn't do that. We actually brought a consultant in, a worldwide renowned consulting firm, WorleyParsons, who helped us understand floods, understand how to mitigate floods. When you look at the flood advisory maps that FEMA publishes, they talk about the flood zones, and they identify how much anticipated level of flooding could take place, and Sandy is one element. The maps are not solely based on Sandy. It's based on a number of factors.

In taking those maps we then asked our consultant to help us understand what happens over time, and one of the things that came back to us was, whatever the amount of flooding was at Arverne substation, 72nd and Beach Drive, the analysis included that we have to plan for sea level rise as one of those aspects that had to be considered. The other one in 200 was the flood level was the one that we had to plan to. When you add the sea level rise, it looks more like a one in 500 year flood, so that was all built into the calculations to determine how high to go.

Now, keep in mind when we started doing Arverne, which was immediately, that was the first station we started because it was a huge catastrophic failure there, you know, those maps hadn't been revised. So, we used the best information we had available, but as we went forward, that's why we brought WorleyParsons in, to help us look at all of the stations, and help us identify, based on the flood maps, based on the experiences of Sandy, based on C25, which is the structural standard that we have to follow for building code of what is the right level of elevation required, and sea level rise was one of those aspects.

MR. GOODMAN: Great. I think you've touched on us, but it sounds like what you're saying is that you just didn't design anticipation of a repeat of Sandy, but it sounds like you took into consideration at least some further change in climate, and other events that could potentially be more severe than Sandy?

MR. LIZANICH: Absolutely because Sandy arguably wouldn't have been the worst thing to hit Long Island, you know, when you look at it from a flood perspective, it looks bad, but, you know, when we plan for the next contingency, that's where we learned from the experts was a little bit around of how do you predict, how do you determine what will be bad. That was why the flood advisory maps were partly based on Sandy, but not solely based. That's similarly in Nassau and Suffolk, the flood advisory maps were not modified like they were in Queens. So, what we had to do there was, again, the consultant helped us understand, how do you make a decision around level of elevation on the other stations like Fair Harbor, Ocean Beach, or Park

Place. That's based upon Sandy, but it's based upon other things beyond because we couldn't rely that Sandy was the worst case scenario for Long Island.

MR. GOODMAN: Similarly, for the transmission lines, when you were designing them for repair to withstand, I don't know if it's 103 miles-per-hour wind or something different, those projects were also designed not just with respect to what happened with Sandy, but what might be the worst case that you can anticipate now?

MR. LIZANICH: Yes, in the case of transmission systems, are our new standards today, and they have been like this for the last -- since about 2008, we designed it to a 130 miles-per-hour, so we're really designing to a level three hurricane is what we are designing to, and Sandy was not near 130 miles-an-hour. So, what was designed to that 130 miles-an-hour withstand did very well. Obviously, the distribution system is not designed for that speed, so therefore, it took some more damage.

MR. GOODMAN: You mentioned the four, I think it's called the buckets projects if you will, covered by the FEMA grant. Is there an ongoing or a plan storm hardening work that is not captured by those four categories of projects?

MR. LIZANICH: Yes, as is listed in our testimony in the rate case, the storm hardening is done routinely across a lot of projects. So, for example, we had talked earlier about the

Kings Highway substation, just take an example, it's going to be built right down the road unless we come up with a Utility 2.0 REV solution, but in building that substation, the design standards for that substation are strengthen and foundation, strengthen and steel, strengthen and insulators to 130 miles-an-hour, so that a new station built today will be able to withstand the higher wind speeds that could take place in a hurricane. So, that standard has been revised, and every substation project that we build going forward, and this has been in place now for about eight years, is designed to that spec, such that we have it. So, that's not specifically called out in the rate case, but I know we had a question that came from one of the organizations that asked that question, and that's embedded within the projects.

On the lines side, any time we install one of those sectionalizers or install a critical piece of equipment on the distribution system, a capacitor bank, a switch, those are installed on hardened poles, larger massive poles that are going to be able to withstand higher wind speeds.

The transmission system, when we build it today, we design it a 230 mile-an-hour such that the poles get a little bit more substantial, but they're designed to withstand, so that they won't come down during those high wind events that we unfortunately do get as a nature of where we're located here on Long Island. So, many examples exist within the rate case and the projects that we do that are built to withstand, and that withstand is built into the standards that we applied moving forward.

JUDGE PHILLIPS: Does anyone else have any questions? With that, do you have anything that you would like to add?

MR. WEISSMAN: We would like to thank all of the parties participating, and I'd also like to thank all of PSEG's witnesses who've provided the information today and throughout the case, and I really appreciate their time, and their commitment to this entire process, to this entire project coming into LIPA.

JUDGE PHILLIPS: I actually just wanted to echo that sentiment. We don't normally go without lunch like this, but I was a little concerned that we wouldn't have time for those people who have to come back for the informational forum to have any kind of substantial break, so I really do appreciate everyone's patience. I know it was a long day. Thank you to those who prepared slides and presentations, and thank you to those who came to ask questions. We do appreciate it, and we're happy that you were able to join us.

So with that, we are adjourned. There will be the public informational forum starting at 6:00 and a public statement hearing at 7:00 p.m. Thank you.

(Whereupon, the technical conference was concluded at 4:02 p.m.)

C E R T I F I C A T E

I, Tommy Phengthavone, a shorthand reporter and Notary Public within and for the State of New York, do hereby certify:

That the witness(es) whose testimony is hereinbefore set forth was duly sworn by me, and the foregoing transcript is a true record of the testimony given by such witness(es).

I further certify that I am not related to any of the parties to this action by blood or marriage, and that I am in no way interested in the outcome of this matter.

TOMMY PHENGTHAVONE