BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the Matter of: :

NORTHEAST JOINT BOARD FOR ECONOMIC DISPATCH :

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The Colonnade Hotel
Huntington Room
120 Huntington Avenue
Boston, MA
Tuesday, November 29, 2005

The above-entitled matter came on for conference, pursuant to notice, at 10:00 a.m.

BEFORE: COMMISSIONER NORA BROWNELL, CHAIR
MASSACHUSETTS DPU CHAIRMAN PAUL AFONSO, VICE CHAIR
NEW YORK DPS CHAIRMAN BILL FLYNN, VICE CHAIR

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P R O C E E D I N G S

(10:00 a.m.)

COMMISSIONER BROWNELL: Thank you all for joining us today in what I'm certain will be a lively discussion about economic dispatch. You know that you've been in the business too long when, in fact, that's an interesting topic.

I'd like to simply open by saying that Congress envisioned what is actually the first Joint Board effort between FERC and the states, asked us to convene and look at issues surrounding economic dispatch in different regions of the country.

This is the last of four meetings, and the goal is to come away with a better understanding of what's working, what's not, how we can improve the opportunities, whether they be in organized markets or unorganized markets.

The way the process will work is, we will look at the transcript of today's meeting, which will be available in a week on our website. You may submit additional materials, either today or to the docket, make comments for 21 days, and Bud Earley, who is here -- Bud, raise your hand -- will collect the recommendations.

We will amass those recommendations and put them out to the Joint Board for comment. We'll meet again at the Winter NARUC meetings when the other regions will also meet, and come to some conclusion, so that we can get a report to Congress as early as possible.

I would remind you that Congress did not ask us to talk about world hunger or RTO finances, or any of the other interesting topics that people like to wax eloquent on; they asked us to talk about economic dispatch.

So if you choose this opportunity to talk about something else, I will ask you to sit down, because we have a lot to do today.

Certainly, there will be more opportunities. I think we all feel very good about the Joint Board process, and I think it's a good opportunity to explore other issues, but I would please ask you to remember what today's topic is all about.

Before I turn it over to my fellow chairmen and the chairs of the other Commissions -- and I'm delighted that you've taken the time to be here -- I'd like to introduce our staff, so that if you have any questions of them, or discussions you'd like to have, the smart people are here.

We have Brian Lee, who runs our Media Group; Sarah McKinley, who is the Logistics Chairman for this; Bill Maroney, who will be presenting Bud Early; my staff, Jim Peterson, Mary Mortin, and Christine Schmidt, the person from whom you got all the e-mails; Jennifer Quinlan is also helping with logistics. We have Jignasa Gadani and Harry Singh, and Dave Mead.

So please feel free to talk to them at any point and to make comments to them. With that, I will turn it over to my fellow Chairs, who are actually together for the first time all morning. We've spent much of the morning walking up and down the hall, trying to find each other. Gentlemen? A before F.

CHAIRMAN ALFONSO: I defer to my senior colleague.

CHAIRMAN FLYNN: As it should be.

(Laughter.)

CHAIRMAN FLYNN: First of all, I would like to thank Nora for putting this all together here. It's a wonderful setup, a beautiful hotel, and, next, thank our host here, Mr. Alfonso, for his taking care of us. I only hope that he will take care of us for the rest of the day and beyond, because I'll be back next week again for -- maybe you'll stay out with us next week.

I don't have much to add to what Nora already said. We're interested to hear what people have to say today, and hopefully -- I want to commit New York beyond this process, that if there's anything that we can do in helping the FERC Staff, as we have gone along putting the report together, please feel free to -- well, you always do pick up the phone and call me, so we're ready to help. I'll turn it over to our host here.

CHAIRMAN ALFONSO: Thank you, Bill. I'd like to welcome you all to our great City of Boston here. Commissioner Brownell, a special note of thanks for arranging the meeting here, the stakeholder process. I thank you -- a big thank you to your senior staff, who actually, as we know, does all the work on all of these events, for all of us, so we're grateful for that.

I just want to confirm one thing. I did hear in the introduction that one of the issues that you did not mention, was LICAP. Is that in or out?

COMMISSIONER BROWNELL: That's out, that's out.

CHAIRMAN FLYNN: Is Commissioner Goldberg here? Sorry.

On a more serious note, the issue presented today, is an important one. I was telling someone earlier today that it's not susceptible to a five-minute soundbite or a ten-minute soundbite, but the reality is, it's all about the ratepayers, all about our consumers and the regulated entities around this table.

We have a platform. We've learned a great deal of what we do right, but it's important to take inventory of things to perfect them.

I've read some of the materials, and I want to thank you all. There is really some thoughtful stuff here. I've just got to find the time to really delve into, and I will commit to doing that.

So, we have a great baseline to work off of, perfect it, adjust it, and learn today. My sense is, Commissioner, that today is a beginning, not the end of this process, so I want to thank you, and I look forward to a good day of engagement.

COMMISSIONER BROWNELL: Okay, thank you. The process is this: We'll open with Bill Maroney from our Staff, who will do a basic economic dispatch 101, and then I think a really wonderfully-drafted report from DOE that will be discussed by David Meyer, who supervised the process.

It's important, I think, to get on the same page in terms of what we're talking about when we say economic dispatch, and then to explore some of the issues that have been raised by DOE. We'll then have questions and answers and go to the RTOs in terms how economic dispatch is being implemented and what their experience is.

We will take questions from the microphones, and please identify yourselves, because this is being transcribed. If you don't want to stand up and be attached to the question, we have index cards for you, so feel free to pass those out to either Sarah or Jennifer, who are right back here in the back row, who will be standing up, and we'll read those and answer those to the extent that we want to. Thank you.

With that, Bill, we'll turn it over to you.

MR. MARONEY: I'm Bill Maroney. I'm with FERC Staff. My job today is to give you the ten-minute soundbite overview of economic dispatch.

To many of you in the room who have been steeped in this for years, quite possibly more than I have, this will be a distortion of sorts. My job is to start us off with the basics, and I'm going to do that by talking about four things:

First, just very generally, what is economic dispatch? And I'll encroach a little bit on DOE, but that may help them get started, too.

I will then talk about two of the main parts of economic dispatch, which is what happens day-ahead, both everywhere and in the RTOs in this region, and then what happens in what's referred to as real time in this industry, that must be a mystery to people outside of this industry.

And then, finally, I'll talk a little bit with just a very brief start on what some possible objectives are for the report that the Joint Board will eventually develop, just to kind of get us started on what the structures are, so we can kind of have a framework on our end for the things that you're going to be presenting to us.

The definition that is actually the definition that's in the section that DOE is going to give the report on, but also the definition that FERC settled on, I believe, as the primary one for purposes of the Joint Boards, and that's the definition of economic dispatch, which I will read to you, which is:

"The operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities."

Well, there are several key parts of that, quite obviously. Although it is the definition of economic dispatch, which is the one that DOE is working with, it also fairly clearly identifies the operating limits of the generation and transmission facilities which are important for secure operation, which is the basic concept behind security-constrained economic dispatch, which fits into the body of the section that convened these Joint Boards.

I'm going to talk about two sort of fundamental parts of the dispatch. Planning goes on for a long time at facilities, but the specific planning that takes place the day before the actual dispatch, looks very explicitly at the expected dispatch in the next day, and includes many of the basic concepts of economic dispatch, looking a little bit ahead of time.

There are several things that are different about the markets in the Northeast and other parts of the Midwest, as well, but what particularly distinguishes the Northeast, is that there's been a long history of regionalization that simply didn't exist in the other areas of the country, and it actually long preceded the use of the regional pool concept as part of the market concept.

And that second aspect is really the other thing that differentiates the Northeast, because it's not really just a process of planning; it's also a process of market development, day-ahead and in real time. And I'm going to talk about those two things in a little bit more detail.

As far as day-ahead planning goes, all power systems -- it's a part of the nature of the power systems that plans need to be developed day-ahead, if you are to operate the system securely in real time.

It's a process called unit commitment, and it's typically going to be based on the forecasted load for the next day everywhere in the country, and small utilities and large have to deal to one degree or another with how to commit a very complex system of power generation, where some units cost a lot to build and are cheaper to operate and some units don't cost much to build, but cost a lot to operate, and all of this has to be coordinated across the very complex transmission grid.

So part of the responsibility is to ensure that this system will be safely operated tomorrow, by looking ahead as closely as possible.

In the RTOs in the Northeast, the process has long been developed as something called security-constrained unit commitment, abbreviated with the acronym, SCUC, which would be pronounced SCUC, which tells you that it was not created by a marketing executive, because if you wanted to make this sound like a friendly process, you would not have called this SCUC and you would not have called the other one SCED.

(Laughter.)

MR. MARONEY: But those are longstanding terms that we have and we use them, and we throw them around, and so I'm going to continue to use them and I expect that others will today.

One of the things that's different about the process in the Northeast, is that it's based on offers, not on accounting costs and the old pool concept, so that differentiates it.

One of the other things that differentiates the more advanced application in the Northeast, is the fact that the unit commitment process is done simultaneously with looking at the limits of the transmission system, so you don't do one and then do the other, and try and go back and forth the way some utilities outside of RTOs may need to do.

So it makes the whole process a lot more integrated and streamlined, and then the market extensions that are consistent with that, produce hourly prices that are the familiar ones that we see both in New York and in New England.

And one of the key things or one of the key reasons to be doing all of this in the market framework, is, once you have in place, a regional dispatch, you need to make sure that any markets are implemented, are consistent with that dispatch; otherwise, you're sending very misleading signals to people, and as some RTOs have found out in various stages of their development, if you don't have a consistent set of signals, people behave and operate in a way that can lead to higher costs and greater risks to your systems.

This whole process is typically based on what participants in the marketplace believe their forecasts to be, and take their -- tell their -- say their available resources are.

The RTOs have a larger responsibility to look, because the whole region is visible to them, to make sure that this whole system is consistent, every day, looking forward.

But every day, looking forward, is every day, looking forward, and then you wake up in the morning and people come in and turn on their lights, and the world is not always quite the same.

And so the challenge that everybody faces, is the real-time dispatch challenge, in which it's necessary to monitor load, generation, and interchange on a second-by-second basis, with both machines and human beings, to make sure that, as everybody says, the lights stay on.

This is a process that is familiar to anyone who's had the pleasure of spending some time in a control room, that where the flows and the voltages levels are monitored very closely to keep them in the reliability limits.

Now, this is something that every utility does. It's something that's a necessity to power systems.

Typically, utilities don't do the level of regional real-time dispatch that happens in this region. One of the effects that that has, is that the system is run in a way that it was run a long time ago here -- a very long time ago, actually.

I seem to remember, looking at somebody's presentation, that we're talking about 20 years before you even put markets in place, that you've been running security-constrained unit commitment and economic dispatch, so I think it's important to recognize that these concepts include both the market environment, but also other environments as well, and they can bring benefits in both cases.

But in the case of the RTOs in the Northeast, just very briefly, as I'm sure others are going to go through this a little bit more, the security-constrained economic dispatch, which is, again, SCED, looks at generation and transmission reliability, every five minutes.

It's not something that you do once and then when things don't follow out with plan, you use some non-economic means. The key here is that the economics and the reliability are integrated on as small a time scale as possible, and anyone who operates power systems, knows how far a power system can deviate from that sort of solution, if it's not constantly renewed.

So you have a process where you're both carefully controlling a system, and also carefully controlling the market signals that come out of the system, because the market signals are highly locational, both as a result of the fact that power systems all have losses, and all of them are subject to congestion at certain times and places.

Nevertheless, the RTOs are sitting there as the agents who will ensure that if corrections need to be made outside the market system, they're there to do it.

But the thing that differentiates the RTOs that use this process for running markets, is that the real-time market prices are actually consistent with the actual physical dispatches. As a result, the online resources are based on the lowest cost.

In the case of the RTOs, the cost is, I think, almost exclusively going to be based on the bids that are given to the RTOs, that may or may not be a result of an entity's own sort of concept of their, say, accounting costs, and so on.

But it's done every five minutes, and the result is that, by and large, you don't have to resort to non-economic means to control the power system in most cases.

So, the examples that occur outside of a framework where things are controlled through the economics, which is that fairly extensive use of a procedure called TLR, or transmission loading relief, is either minimized or eliminated in the context of the RTOs. It is certainly a potential topic for discussion about the degree to which it becomes necessary.

But, by and large, it's one of the big benefits of running the power system consistent with the economics. The economics and the reliability are, in fact, two sides of a very similar coin, and when you put them together, the coin is worth a lot more.

Finally, I'd like to just very briefly touch on the broad objectives and issues in the Joint Board report, and this is this last set of topics, something that we try to address to everybody in a fairly consistent way. So, in some of these things, they may not seem like the leading topic in your region, but they are certainly topics in other regions in which your experience will perhaps be very useful and instructive.

In general, we sort of see a report going to be part description, part consideration of improvements that the Joint Boards and participants in the marketplace bring up, and then a consideration of how those -- the issues associated with those improvements.

And I won't go into all the details here, but, clearly, a couple of the issues that arise, in general, with what you would want to know about economic dispatch in a region, is how wide is the geographic scope and what resources are included in the dispatch?

Pretty much, much of the regionalization and consolidation of scope in these regions, happened a long time ago, but they're still are a few dispatches and I well know that there are any number of issues around the coordination of those dispatches and central consolidation.

But that's just a topic that's out there. Our purpose here is not to sort of guide the set of recommendations, but to just provide some framework.

And then there are a lot of issues around how a dispatch is implemented or practiced that are probably different as a function of the way the economic dispatch is done, but many of them still would apply in a place like New England or New York, and that's what software tools are used, in the case of New England and New York, what's the coordination of dispatches and how this communication works with generators and other participants in the marketplace.

And, finally, there could be a number of issues around institutional or technical impediments to development. These can occur at any number of levels.

Outside of RTOs, one of the issues may well be what sort of Order 888 changes would be needed, to the extent that utilities want to try to capture the benefits of economic dispatch without going through the full development of RTOs?

Then issues to consider for the improvement of dispatch -- and I know that a couple of the presenters from the RTOs, are going to talk about these fairly explicitly, and that's just what improvements could be considered, whether potential benefits and costs of these improvements -- and some of these can be basically looking back to when you instituted the dispatch, what was it that you experienced?

So, with that, hopefully fairly brief basic overview -- at least I hope it was basic -- I am ready to turn it over, I believe, to David Meyer and DOE, and, after that, I'll be here for questions.

MR. MEYER: Thank you for the opportunity to talk about a recent report that DOE issued on economic dispatch. Our report was a mandate from the Energy Policy Act of 2005.

The Congress told us to study current economic dispatch procedures, identify possible improvements, and analyze the potential benefits of such changes.

Bill has already given you the definition that was in the Act, and it -- personally, I'm pleased with the body of comments that we got to a questionnaire that we put out. No one among the 92 commenters, no one took issue with this definition, so the definition itself seemed to be broadly acceptable, and that certainly gave us a useful basis to go forward.

The plan that we used for our report -- and, recall that we had 90 days to do this study -- so the plan that we came up with, was to prepare a short questionnaire of six questions, which we -- questions about economic dispatch practices and possible improvements.

We circulated the questionnaire to stakeholders through seven trade associations. We appreciate the help that we got from the trade associations in getting the questionnaire out.

The 92 responses that we got back, were very diverse in terms of the sectors of the industry and the stakeholders represented, so we felt that we did get a very good and broad response.

We drew very heavily on these comments in preparing the report. We also reviewed 25 existing studies that treat the subject of economic dispatch in one way or another.

These were studies that were prepared essentially for other purposes, but, nonetheless, in the course of meeting the particular objectives of the report, they found it useful to review the practices of economic dispatch and the effects of economic dispatch.

In terms of the findings, we found significant economic benefits associated with economic dispatch, and we found that the benefits tend to increase as the geographic scope and the electrical diversity of the area under unified dispatch increases.

Retail customers benefit if the cost savings are passed through in retail rates, and, finally, economic dispatch tends to reduce fuel use and emissions, as high-efficiency units frequently, although not invariably, displace lower-efficiency units using the same or similar fuel.

As Bill has already described, economic dispatch is what might be called a constrained cost minimization process, and it is -- to begin with, yes, it is security-constrained in terms of meeting reliability requirements, but there are many other constraints that are involved as well.

For example, it's necessary to take into account, the ability of a given generating unit to shift its output at short notice. There's considerable variance in that regard.

And there are also scheduling limitations imposed by environmental laws, hydrological conditions, fuel characteristics, and things of that kind.

So, that this means that, operationally, economic dispatch gets rather complex. The concept itself is very simple, but the application is quite complicated.

In terms of the existing studies that we reviewed, there were two main types: One of them was studies that were prepared in association with the proposed formation of ISOs and RTOs, and then the other category was studies that had been prepared, focusing on dispatch of independent power producer capacity.

And neither of these studies, neither type of study was designed to produce the disaggregated assessment of benefits of economic dispatch that the Congress envisioned in the two sections of the Energy Policy Act.

So, as a result, in the 90 days that we had to work on this study, we were, quite frankly, not able to provide the degree of detail in regionally disaggregated form that the Congress asked for.

But this is an effort that we're to do annually, that is, we are to produce an annual report to Congress on this subject. So this gives us some additional things to focus on for future reports.

The RTO studies, that is, the studies pertinent to the formation of RTOs and ISOs, found benefits in the range of one to five percent of total wholesale electricity costs, and the IPP studies presented benefits in a somewhat -- in a conceptually different manner, that is, they presented benefits in terms of total variable production costs, so you can't compare these one-to-one, but the range of benefits that the IPP studies found, were eight to more than 30 percent of total variable production costs.

Finally, some of the issues associated with economic dispatch -- and here, as Bill has alluded to, the regional practices or the regional circumstances differ very considerably, so these issues don't necessarily pertain to all regions.

But the non-utility generators assert that some vertically-integrated utilities use dispatch processes to favor their own generation, and in this -- operationally, this could occur when some of the operating rules or practices used in economic dispatch, may have the effect of excluding non-utility generation capacity from the economic dispatch stack, or, alternatively, shifting a resource to a less advantageous position in the stack.

Such practices may include rules for determining whether non-utility generation receives long-term contracts for their output, or long-term contracts for the use of transmission capacity, and, finally, whether non-utility generation provides individual generating units, provides sufficient operational flexibility to qualify for economic dispatch.

Now, clearly, to qualify, you do have to be willing to operate with some minimum degree of flexibility.

In terms of improvements, again, this pertains to all of the Joint Boards, and they may wish to examine economic dispatch practices in their respective areas to determine whether non-utility generating capacity is treated appropriately.

DOE urges non-utility generators and power-purchaser communities to work together to ensure that the contract terms adequately compensate non-utility generators for providing operational flexibility.

Now, if the contract isn't worded in that respect, I wouldn't expect that flexibility would necessary be offered.

Another possible area for improvement is to focus on the tools used in economic dispatch, that is, the software, the data, the algorithms, and the assumptions, and we feel that there is room here for a systematic review aimed at improving the quality of these tools.

Finally, economic dispatch is dependent on accurate load forecasting, and improvements in the accuracy of such forecasting will enhance, in turn, the efficiency of economic dispatch.

So, with that, I will take whatever questions people have.

CHAIRMAN ALFONSO: If I may, thank you very much for the presentation, and I should say that it's a very thoughtful, great background, so my compliments to your other colleagues in the production of it.

One of the issues that we've -- I know we'll engage a bit, is how to quantify those benefits. We live here in New England and New York and throughout the different states, and many price increases, commodity price increases, and the political nature of that is very difficult, as one can imagine.

So when we talk about economic dispatch and the benefits, when one says one's five percent in one of the studies presented, can you reflect, if you can, on whether those analyses are universally accepted or have they been critiqued heavily in terms of the conclusion of the, say, one to five percent, even just generally speaking.

Any thoughts?

MR. MEYER: That's one to five percent, as compared to what? These studies were comparing economic dispatch over a wider region as compared to the earlier studies.

So, I think that in the case of this region, those benefits are already being achieved, because dispatch here is done across a wide area. So, any remaining benefits are going to be increments added on to what is already being achieved.

CHAIRMAN ALFONSO: I would ask any of the other members, in your own presentations, that maybe we can come back and have that discussion with other colleagues, as well.

COMMISSIONER BROWNELL: Let me introduce my colleague, Mr. Robert Keating. It's a pleasure to have him here.

MR. KEATING: I'm Rob Keating, with the Massachusetts DTE. Let me join Jim and thank you, Mr. Meyer, for a great presentation.

I have a question here, and I know that this will probably raise some hairs on the back of some people's necks, but, then, why not, right, if it keeps everybody awake.

On page 11 of your report, you talk about the difference between economic dispatch and efficient dispatch. The reason I raise the issue, is that I think we all know, and, as you point out, there are times when economic dispatch will not necessarily mean efficient dispatch, because of just the way the system is operated.

And we recognize that, but I wonder what the Department of Energy will be doing in the longer term, because, as I suspect, and I think we probably generally agree, many of the people who push efficiency with good reason and good cause, and noble causes -- and it is important -- may use the Congress to push the efficient dispatch issue, maybe ahead of the curve.

I can see some arguments with that. Obviously, if we have efficient dispatch, that could mean affecting the supply/demand portfolio of natural gas, which is very tight and driving up prices. Then if you drive down prices, obviously we have an economic dispatch.

What will the Department be doing, if anything, with regard to further studies on the efficient dispatch issues, versus the economic dispatch issue?

MR. MEYER: First, I think we'd have to come up with some workable concept of what efficient dispatch is.

The advocates of efficient dispatch, haven't managed to push their thinking that far yet, I don't think.

The best I can do is to think of it as dispatch on the basis of heat rate efficiency alone. And then when you look at economic dispatch as now practiced and see all of the other things that need to be taken into account, if you're going to dispatch on the basis of overall unit efficiency, economic efficiency, you realize that going down the path of efficient dispatch, would really take you off the beacon of economic efficiency.

How far? We haven't tried to model that, but, to me, it certainly raises questions about the merits of going off the beacon of economic dispatch, which does benefit ratepayers in terms of lower electricity costs.

I realize there is the feedback associated with possible savings of natural gas that would eventually get back and benefit consumers, also, nonetheless, the question just jumps out, well, if you know you're going to be experiencing some significant additional costs if you go down this efficient dispatch path, are you going to see compensating benefits?

Would the associated benefits be sufficiently large to make it worthwhile to shoulder those additional costs? It's a complex set of questions, and, as of yet, we have not tried to do that kind of modeling.

Obviously, we could, if there appears to be substantial interest.

MR. MARONEY: David, if I may, I would like to add something, because there's an obvious alternative, which is to ensure that all the resources are, in fact, in the dispatch, which I think we can support. That seems like the first step.

If I may, it isn't what's done today, versus some concept of an efficient dispatch. Those are to be appropriate alternatives to consider. Once you go down that road, then I think someone needs to put on the table, a reasonably clear definition.

Usually it's efficient dispatch in the context of a set of gas plants, very often in a particular region, and that's the context in which it is brought up. I haven't seen anyone tackle the larger issues yet.

If you wanted to continually dispatch on some measure that wasn't monetized and wasn't on the basis of cost, it's risky, I think, to start doing explicit analyses in advance of a reasonable design of what that analysis should be.

I'm not saying they shouldn't do it, but I think there is a little bit of a burden, a definitional burden, on what the alternative concept is.

MR. KEATING: Certainly not to debate the issue, except in a collegial way, I certainly agree that with economic dispatch, we'd want to get the price economically, efficiently, out there, as quickly as possible, especially in today's market where prices are very, very high, and are affecting our consumers, and, believe me, as a state commissioner, we see that firsthand.

But the reason I raised the issue is, my concern, in the larger public policy issue moving down the line, is -- and I don't have the answer to this and I'm not suggesting an answer, but is there at some point where we need to push the more efficient generation?

I mean, I have read where some companies have on some of their new, combined-cycle plants, just closed them down, especially down in the Southwest. They're not running them, so, in fact, if it wasn't for we termed or what the ISO New England termed "the old dogs," last January, we'd probably have a problem here in New England.

Thank God for them, but yet for a larger public policy purpose as we move down the line, if, at some point -- how are we encouraging the new generation and the new technologies in another industry that we regulate. In the telecommunications industry, we see technology advances really have changed things and prices come down and things move forward.

It's much different in the electric industry.

It's a much slower economic change, but yet there is some economic change, and that's why we still have so many of the new combined-cycle plants.

But if we had combined-cycle plants that are highly efficient, using much less gas, and, from a societal standpoint, are much cleaner, and we're not running them because they can't compete because somebody's got the higher mortgage rate on them and the older plant is all paid for and it can underbid them, but yet uses more natural gas and pollutes more, what's the offsetting economic balance to that, again, not for the short term, but for a longer-term policy issue? That was the thrust of my question.

MR. MEYER: Well, in parts of the country or in any part of the country, if there does seem to be existing, efficient, gas-fired capacity that is, arguably, under-utilized, then I think, from the Joint Board's perspective, the question would be, what are the facts on the ground here?

Is it, in fact, the case that the capacity is not being adequately utilized, and, if so, why not? Why doesn't economic dispatch, as practiced, lead to increased utilization of that capacity?

COMMISSIONER BROWNELL: Other questions?

MR. KRAPELS: I'm with the Neptune Transmission Project, and I'm also one of the authors of one of the studies on the effects of RTO formation. I just finished one for PJM.

As such, wanting to do an honest job on a difficult subject, it struck me that there were four different sort of principles involved here. One was that the decision to do this, to go for this kind of economic dispatch, was a decision based on economic philosophy, at the end the day, and that economic philosophy simply is educated by the telecom and airline experience, saying, you know, there were some very interesting results in those industries.

Generally speaking, I would say that most economists would say that they have been to the consumers' welfare.

In that perspective, we're still in the very early days in the electric industry. That's sort of the philosophic angle.

But when you try to prove the benefits and turn to the technocrats, to guys with models, it's kind of self-evident and a truism, that if you have a bigger market with more generating plants, that you will get benefits from a larger area in economic dispatch, because of the portfolio effect and because of the general way in which the system works.

Most of the technical studies would say, yes, you get a 75-cent per megawatt hour difference, if you make PJM from one size to a bigger size, just because of the increase in portfolio diversity.

If you ask the economists or the econometricians, well, what are the impacts of all of this on the market, they will add the volatility component. They will say, well, if you want less certainty and more competitive struggle, you will have more volatile prices, and we've seen that at the end of the day, that volatility is a net detriment for consumers or not.

The only answer you can give, honestly, is that time will tell. We'll see. It's still too early.

The last perspective is the perspective of the structural guys who say we haven't figured this whole thing out yet. We have this he-who-must-not-be-named problem on the policy of capacity and how to integrate capacity into the system, and it affects everything.

We're still not at the point, I think, where we can do definitive studies and prove to everyone's satisfaction that we've got it all figured out.

COMMISSIONER BROWNELL: Good observation, but, put in those terms, that's the very kind of political struggle that the states, the FERC, the Governors, are struggling with.

We're talking about customers, we're talking about their social and economic wellbeing. Some would say, you're undertaking an experiment and saying that we don't know the outcome, and yet I think you need to put it in the larger context, which experience with other markets would suggest very strongly that while we can't exactly measure the outcome, the outcome has been always in some ways, positive, whether it's new technology, which, in this market, would deal with some of the environmental issues.

So I hesitate to say that we don't know. We actually do know. We're just having a hard time quantifying it in a way that people can stand up and say, here, is that a fair characterization of where you are going?

MR. KRAPELS: It is. I come out very strongly saying that the benefits will be and are quite large already.

The problem is, it's hard to be precise, and any study that you do, it's so easy for people who are against your conclusions, to come out and micro-criticize particular pieces of it, and say, you didn't do this part right.

COMMISSIONER BROWNELL: It's interesting that some of those people say you didn't do it right, but they don't tell you how to do it, so I always have to kind of discount them.

I have a couple of questions, if I may. You mentioned that the tools used in economic dispatch, should be subject to a systematic review. That, to me, is maybe one of the most critical components, because we've seen, for example, that if you manipulate assumptions and data, you do not, in fact, get effective economic dispatch; you do end up with kind of that disparate treatment of generation.

This is not true in organized markets, but we've certainly seen it in unorganized markets. How should we undertake that review? Should there be some additional standardization, whether it's organized or unorganized markets, that would perhaps lead to less expensive software costs, more transparency, the kinds of things that we find important to measure, whether, in fact, we're doing a good job or not.

Could you speak to that a little bit, and anyone else may comment, as well.

MR. MEYER: I'm certainly here to listen and get the views of people who are using these tools, people who have sponsored the development of these tools over a long period of time in terms of their thoughts and how they might be improved.

I guess one of my chief concerns is matching the tools to the user. We are dealing with a very disparate set of users.

It's not that we could simply come up with some approach or some tool that was going to do well for this very broad set of parties that would be using it.

I think we maybe have to group them into categories of users and then try to identify best practices for those respective types of parties. That would take a lot of input information to make it work, so we're hopeful that we'll get some good suggestions on what people think would be useful ways to approach this and where they think the major potential gains might be.

MR. van WELIE: Good morning, I'm Gordon van Welie, ISO New England. I have just a couple of thoughts.

This is one of the areas where market have a substantial benefit over non-markets. Later on, when we get into my presentation -- and I'm sure the same is true of Mark's -- the transparency that markets bring, does a number of things:

It increases the quality of the economic dispatch, going to the data and the systems that are required in order to run and settle a market. We go through a rigorous process. It's a bunch of jargon, basically, but it's a set of standards and practices that we've copied from the banking industry.

We go through a very rigorous audit every year to validate that we have settled the market in accordance with market rules, and we're actually operating the market in accordance with market rules. We've also at the ISO, since we implemented SMD 2003, have gone through the rigor of an annual certification of the dispatch software.

If you look at dispatch software, the economic dispatch software, the unit commitment software, by an independent consultant, to verify that the algorithms that the software code is made up of, is actually consistent with the market rule, so there can be no discrepancy. we asked them to validate that for us,

We do that because we know that there are billions of dollars at stake. I think that this year, we're probably looking at $10 billion worth of value having cleared through our market, if you take both the bilateral and the spot markets.

Our participants need this in terms of complying with Sarbanes-Oxley. The need validation certification from our independent auditors, that we've done our job, basically.

The other part of how markets and transparency, I think, help evolve economic dispatch, is that what you do, the minute you're making visible, the results of the dispatch, you have a lot of people interested in those results, and people are worried about why A happens, versus B.

You need a lot of scrutiny and discussion, so what happens is, that forces the marketplace and the ISO to evolve the rules and to evolve the dispatch to eliminate those problems that then surface. I would submit that there would probably be a never-ending stream of refinements that can be made to economic dispatch.

We'll talk about some of the ones we've got on our near-term horizon here in New England. I think that's where markets help a lot, because you have opened things up and made it transparent for a lot of people to ask a lot of tough questions. That then puts pressure in the right place to resolve the problem and make sure that the technology and methodologies evolve accordingly.

COMMISSIONER BROWNELL: Don?

MR. SIPE: One of the interesting things, Gordon -- and I'd be interested in your view on this -- is that it's not always clear from the outside that the lack of standardization in a lot of how economic dispatch is handled across regions, whether that's due essentially just to the anomaly and the historic fact that you have different systems and different programs in place to begin with, or whether there is underlying philosophical difference about how a system ought to be dispatched that's reflected in the various control areas and the pools; whether it's being driven more by a philosophical determination that we don't want to do things exactly this way, or whether, in your mind, it's just more the fact that the systems developed independently.

Sometimes from the outside, it's not clear that all of the reserve practices and other things are consistent across pools, or inconsistent, whether it's a philosophical difference or just an historical anomaly. It's very tough to shift out.

Do you have an idea about what are the major drivers there? If it's the philosophical one, then just sort of high-level discussions about what we ought to be doing and how to prioritize, would seem to bear some fruit. If it's just the historical techno-problem, well, we don't have matched systems, that seems like something that a lot of us sitting around the table here today, wouldn't be able to do much about, other than to turn it over to a computer program.

MR. van WELIE: My view is that there are probably three major things that are barriers to greater standardization: The first is the typical engineering, not-invented-here syndrome, which happens; it happens in every industry.

This industry is not unique. Utilities typically have large engineering staffs, smart people who all think that they can do the job better. There is some benefit in that in some respects, but there are also some costs to that, as well.

So you've got that as a culture, I guess, within the industry. Also, if you looked at the market participants or the stakeholders that are affected by those markets, there are economic entrenchments.

So, the market rules have been negotiated, obviously, often with great pain and deliberation, in order to ensure certain economic outcomes in a region, so people are reluctant to give that up. That's a very difficult thing; that's even probably a harder thing to shift than the engineering barrier.

And the third, really, is the control. If you look at it from the perspective of influence over outcomes, at a regulatory level, in different regions, how one has -- how one gets certain results from the dispatch of the market and how, from a public policy point of view, you actually influence the outcomes, I think that has enormous influence, as well.

The problem is that standardization -- I was and still am a great supporter of standardization. What I've learned is that it's a very hard thing to achieve, because of all of those barriers.

You've got to break through those barriers to get to standardization, and then reap the benefits of standardization.

So I think what we have here is a situation where this is not all controlled by one large company. If this were McDonald's and we were trying to standardize selling a billion hamburgers, we would find a way of standardizing it very quickly.

But it's not that way, and we've got to live with what we've got.

MR. LYNCH: May I add to that? This is Mark Lynch with the New York ISO.

Ed sort of touched on this a little bit. This is an industry that's really sort of still in its infancy in some ways.

I think a lot of these markets have evolved to different levels of sophistication or just complexity, just sort of through a timing difference here.

When you look at the different markets, there are some that are more advanced than others. There are some that are brand new, coming out, basically issuing the day-one markets, the day-two markets.

I don't think we've reached a point yet in the evolution of these markets that we can look at standardization across the board. Not everybody is going to jump in with both feet into the water; everybody is going to have to go through a certain evolution period to get to where you're going.

Depending on your market participants, the political arena, and basically the capability of the infrastructure you have, you're going to go to different places quicker than maybe some other markets that you have there.

Standardization is something that I think is going to have to come in the future, as opposed to looking at it, you know, as an event that will happen today.

MR. CORNELI: Steve Corneli, NRG. One area that I think offers a lot of potential for policymakers and the market participants and the folks we have who have to try to manage these markets and design them to find best practices and compare them and understand them, are the reports of the independent market monitors that are published annually in each market.

This is something that the Commission very wisely insisted on in setting up RTOs, was to have market monitors who not only look at the kinds of things that Gordon is talking about in terms of are the rule actually being applied consistently, but also looking at are those rules really structured quite right, or should they be improved?

That helps get above the sort of economic self interest of all of us that sometimes leads to the lack of mobility or change that Gordon pointed out.

So those reports, I think, are a real resource for everyone to try to understand how this works and how to make it work better across related or different regions.

COMMISSIONER BROWNELL: Thank you. Gordon, maybe you and Mark can touch on it a little more in your presentations, which we're actually going to get to, unless the Commissioners have any more questions.

I'd like to know more about the certification process, if you could submit that for the record, because it strikes me that if standardization is un-achievable -- I still think it should be achievable, but that's another day -- I think it would be good to look at a certification process, because I think that could work in the non-organized markets, as well, where the lack of transparency and understanding of the economic dispatch models being used, has been a real issue.

Yes? Identify yourself, please.

MR. FULLER: Pete Fuller with Meritt's. Thank you for the opportunity, Commissioner. I know you want to move on.

I want to echo, first of all, everything that's been said here. People have caught -- or are on the same page, that in the Northeast, we do have the benefit of many, many years, and we probably are at the state of the art for economic unit commitment and economic dispatch, and hopefully we're at that point now and we're looking ahead in this particular forum for where we go.

My comment or question here is sort of building off of the definitional issues, the tools issues, and the refinements issues that have just been brought up in conversation. The thing I'd like to throw out for people to consider, and hopefully panelists will be addressing this later on or we can pick it up at some point, is the extent to which the tools and the philosophy and the approach, the policy, addresses all of the security constraint that exists in the market or in the system.

Certainly we are at the cutting edge, but we all know that there are economic actions that are taken outside of the software tools, outside of the pure security-constrained dispatch and the unit commitment that have market effects and reliability effects.

They are necessary for reliability, but they are not always captured efficiently in market outcomes. So I think we kind of have three paths in front of us: The path we've taken so far, which is take non-economic actions and made side payments or uplift; then -- and I think that's proven to be sub-optimal for a number of reasons.

Then you have two other alternatives, going forward: Continue to take non-economic actions; let operators operate the system in accordance with what they know to be necessary to maintain reliability, and find a way to capture the price and cost impacts in visible market signals, so that, again, the competitive markets have the ability to react and respond and produce the outcomes we want, or -- and this goes to the tools question, and I honestly don't know whether it's feasible -- overhaul the tools so that the security constraints fully recognize all of the services, all of the limitations of both the generators, the transmission systems, and so forth, and capture that whole ball of wax and then let the software chug away and produce locational prices for all the products and services to make sense.

I'd like to just throw that out for folks. I don't know if, Commissioner, you want to take responses now, but hopefully that will be a topic as we go forward. Thank you.

COMMISSIONER BROWNELL: What I'd like to do is have Mark and Gordon comment on that, to the extent you can, and then we'll have other comments on that. Thank you. I appreciate good suggestions. I don't know if you toss a coin to see who starts first, but whomever.

MR. LYNCH: Do you want me to go on to the presentation, or do you want me to address some of the concerns that Mr. Fuller --

COMMISSIONER BROWNELL: I'd do presentation and then, to the extent that you can address it --

MR. LYNCH: I think we touched on some of those things, actually, in the presentation, when I talked about some of, I guess, the more specifics of the New York market design.

Again, I'm Mark Lynch with the New York ISO. I would like to thank you for the opportunity to address the Northeast Joint Board on Economic Dispatch.

Commissioner Brownell, I appreciate the opportunity, Vice Chairman Flynn and Chairman Alfonso, and the rest of the Chairs and Commissioners from the other New England states. My presentation will be handed out up here. I think there are some additional copies out there, if anybody doesn't have it.

Basically, I'd like to give a quick overview of the New York ISO. I think some of the New England Commissioners have not seen that before, so I'll talk a little bit about the New York experience and actually respond to questions that the Commission proposed to us to answer.

When you look at the New York ISO control area, we are a single-state ISO. We have a population of a little over 19 million. We are serving New York City, the financial hub of the U.S.

In 2004, we had a load of just a little bit over 160,000 gigawatt hours, reported at peak last summer, a little over 32,000 megawatts, almost 11,000 miles of transmission line. We have a required installed capacity of a little over 37,000 megawatts for our forecasted demand and reserves.

We have over 335 generating units that we commit to dispatch. I think that one of the keys in looking at our market to basically indicate the activity in our market and the sophistication in our market, is that right now, even with a single-state ISO, we have 292 market participants, which I think is quite a few for a single-state ISO.

Looking at the evolution of the New York ISO, after the blackout in '65, the utilities in New York formed the New York Power Pool as a result of that blackout. Basically what they did is, created a pool to pool the operations and essentially look at how they were going to control the reliability of the overall state system.

You can see here that in 1977, essentially what we did is, they used a form of economic dispatch. They went into an automated version that basically included a security-constrained provision that you heard about before, and actually automated that economic dispatch.

That has been in place essentially since 1977, quite a long period. Pursuant to the FERC Order 888 and then the New York Public Service Competitive Opportunities Order, the NYISO began its operation back in December of '99.

Right now, we're looking at -- we've had over $40 billion in market transactions. One of the big keys and milestones for us was that in February of this year, we actually put out a new market platform. It has a lot of enhancements and I'll talk about that a little bit in my presentation.

That basically laid over the past security-constrained economic dispatch system. It provides a lot of additional benefit to our market participants.

The markets that we administer: We have the energy reserves and regulation and all of those are co-optimized on both the day-ahead and real-time. We do provide for the least production cost entities to be committed and dispatched.

We do have an installed capacity market and our TCC market, which is our transmission congestion market.

I want to talk a little bit now about the overview of the state and the implementation of the security-constrained economic dispatch. The NYISO, as well as our predecessor, has used the security-constrained economic dispatch, as I mentioned, since 19777.

There have been significant benefits that have been realized, statewide, both under the New York Power Pool and the New York ISO. The security-constrained economic dispatch really does provide the framework for the NYISO's wholesale markets to basically indicate and show locational pricing. I'll talk about that a little bit later.

And the security-constrained economic dispatch also ensures that the most efficient set of resources will be used to meet reliability criteria, especially in our highly-congested bulk power system. This is even more important in and around the New York City and Long Island areas.

When you look at some of the history here and the use of security-constrained economic dispatch, it has resulted in a more precise and automated economic dispatch method than the historical practice, basically of pricing and scheduling bilateral energy trades.

This is really going back to the old Power Pool days. It was sort of the bilaterals between the different bilateral or fully-integrated utilities.

Under SCED, we were able to come in and actually do a more efficient pricing and scheduling of these transactions. It allowed us to do a more automated scheduling of economic energy amongst the members, and basically removed those time constraints, and, by going to automation, it took away that manual requirement that we had before.

It also allowed the development of an interchange evaluation program that allowed us to facilitate external transactions, not only with New England, but also with our neighbors up in Canada, the problems with Quebec with the EISO now and Ontario, and Hydro Quebec and over in PJM.

I think this is an important point: Without the security-constrained economic dispatch, you would not be able to facilitate this. In our opinion, it's sort of integrated into one of the benefits that you actually glean from security-constrained economic dispatch.

It also allowed us to basically allocate a more efficient reserves market, basically among the New York Power Pool members.

When we look at some of the economic benefits of security-constrained economic dispatch, to use an example, in 1981, out of the New York Power Pool operating reports, basically the New York Power Pool estimated economic savings of $281 million, basically due to the security-constrained economic dispatch and the external economic energy transactions.

This was a representation of about a 24-percent overall savings. I think that's very significant here. We got total billings that year of $905 million, and you're looking at 24 percent savings, just by security-constrained economic dispatch. That's very significant.

If you look at, assuming, conservatively, $100 million benefit over that period from '77 to '99 that would translate into over $2 billion in savings.

Essentially, we look at the $100 million as a very conservative number. We did not have all the datapoints in here. We had a few. Some were below $100 million, substantially; a lot were above the $100 million, and taking the $100 million sort of as the median here, I think that is a very conservative estimate.

When you look at the benefits of the security-constrained economic dispatch in the New York ISO market, basically, since 1999, we have operated a fully co-optimized energy and ancillary services market, essentially overlaid on the previous security-constrained economic dispatch framework.

This has provided for the enhanced reliability in the frequently-constrained system. It's provided the least-cost electricity for our consumers, and it's essentially provided the well-functioning market that has encouraged significant participants.

As I mentioned before, we have over 292 market participants, which is quite a large group for a market of our size.

One of the things that we see with security-constrained economic dispatch, is that it really does provide a basis for indicating and calculating locational marginal base pricing. We retained security-constrained economic dispatch and used it as our basic platform.

It does give us the capability, as I mentioned before, to determine, commit, and then dispatch the most efficient set of generating resources. It does produce locational pricing, reflecting load, transmission congestion, and marginal losses.

It allows the establishment of locational prices, both in the day-ahead and real-time markets, the two settlements, and it supports, as Gordon mentioned before, the providing of transparency of pricing, basically to allow congestion costs to be managed, using the financial hedging tools that are out in the marketplace.

It also provides the locational signals for the location of new capacity. What we've seen, if you flip the page here, is that it's sort of a chart of where new generation has come on since 1999.

This is new and those under construction, but if you look at the eastern part of New York where we had the highest congestion and the highest constraints on the system, you can see that up in the capital region, we had a little over 1700 megawatts; down in New York City, over 2,000; on Long Island, just about 800 megawatts.

It tells us that the locational pricing is sending the right signal; it's telling the entities where to put the generation, where to locate the investment, and with the foundation of the security-constrained economic dispatch, basically it's providing the platform to us to get those locational pricing signals.

That's a real quick summary, sort of an overview of the New York ISO, sort of how we got here, and the transition. What I'd like to do is to go in and respond to some of the questions that were proposed to us. I'll go through those, I guess, as presented, in sort of an order here.

The first question was: What are the benefits and the costs of the security-constrained economic dispatch, compared to the previous system used for dispatch or other potential alternatives?

For New York, some of the benefits that we saw were the inefficiencies in the pricing and scheduling of bilateral blocks, which were replaced by more precise economic dispatching methods; the automatic scheduling of resources removed the constraints associated with the bilateral transactional scheduling.

It provided a process to evaluate purchases and sales from our neighboring control areas. And you sort of asked about the costs; what are the costs?

I wasn't really sure, at first, what you were really driving at there, but in looking at it, essentially the costs of implementing the original -- and I'll go back to the 1977 era here -- was the cost of putting together the New York Power Pool and essentially putting in place, that central dispatch organization, that supporting organization.

I'll apologize that I don't have that cost data. I don't know exactly what that is, but the cost was basically pulling together that organization that did the central dispatch for you and allowed you to look at the entire system and basically facilitate that.

When you look at what specific benefits has security-constrained economic dispatch offered, can you quantify these benefits, and, if so, please do? Significant savings have resulted from the use of security-constrained economic dispatch.

As I mentioned before, the New York Power Pool had indicated that they had a savings in 1981, for that year alone, of $281 million, which, if you translate into 2005 dollars, is over $600 million in savings.

I mentioned before that in February of this year, we actually instituted and enhanced SCED platform that basically provided additional enhancements to the original platform. We are now providing a real-time unit commitment function capable of performing economic commitment decisions, essentially every 15 minutes for quick-start resources such as gas turbines and hydro units.

We have an enhanced, multi-interval two-and-a-half hour look-ahead, which co-optimizes solutions for both energy and ancillary services. We have the full, two-settlement ancillary services market with the day-ahead and the real-time, then we have the two settlements and ancillary markets that provide for generating units to meet reliability criteria, committed to the day-ahead, so that they may be available to meet the real-time operations.

What lessons did you learn from implementing security-constrained economic dispatch? A couple lessons:

It has proven to be very effective in automating the selection of the most efficient set of generating resources to meet system requirements. It's an invaluable tool to address transmission system congestion in highly-constrained areas. I would note that in 2004, we saw that 70 percent of all hours were constrained in New York, in New York City, and 50 percent of all hours were constrained in Long Island.

If you look at the southeastern portion of New York, we're in a very highly congested area. Basically, the frequent congestion requires a precise, automated, and efficient way of dispatching units within SCED.

I sort of give you a couple of lessons we've learned here. Basically a good example is that we basically use the SCED system as a platform to get some benefits in controlling operations.

What we've done, actually, in New York City, beginning in June 2002, we began using the security-constrained economic dispatch system to provide operational control of specific New York City control areas, basically the nine load pockets within New York City, getting in the granularity, which we did not do before.

We did it pretty much on a bulk system; we did not get into specific load pockets. Essentially, what happened was, the system operators had used the manual dispatch directives for dispatching units within the New York City load pockets and were basically paid in their bid costs. This essentially resulted in higher uplift costs.

Since, as I mentioned, since June of 02, we have locational pricing now that purely reflects the congestion costs, New York City transmission constraints, the New York City uplift costs, as a result, have been dramatically reduced. I note that we had an 82-percent reduction in real-time uplift from 2002 to 2003, which indicates getting down into the lower granularity, especially in higher-constrained areas, which is actually providing an economic benefit to all consumers.

The locational pricing basically reflects these costs in the real-time spot markets, and does provide more transparency and allows individuals to basically come in and manage these congestion costs through financial hedging devices that are available out in the marketplace.

How does the operation of the SCED relate to the operation of a regional market? Essentially, our security-constrained economic dispatch is essential to the operation of the regional market. I really can't conceive of the capability to have an organized market without some type of security-constrained economic dispatch.

The New York ISO uses the SCED to co-optimize the economic dispatch solution, basically to provide, again, the least production cost available to meet both. And I think this is important: Energy and ancillary services, we don't do it just for energy; we do it for both energy and ancillary services, so we're looking at entities to come in and to provide not only their energy costs, but their startup costs, their regulation costs.

We basically co-optimized that to get the best, least-cost production, basically commit those units and then dispatch those in our marketplace.

The marginal clearing price for the energy and ancillary services derives directly from the security-constrained economic dispatch, both the real-time and the day-ahead. Then the security-constrained economic dispatch provides the optimal dispatch that allows the transparency and predictability to the marketplace.

Gordon alluded to this before, and I really think that the key to a marketplace is the transparency and predictability, basically how people can actually interact and perform in a marketplace. The more transparent it is, the more predictable; the more they understand the reason why you are dispatching the way you do, why pricing signals are being sent the way they are, the better they can react, the more comfortable they are with the market, the more they can model this market to basically make investments and put more resources into the market.

How would a market operate in your region without the security-constrained economic dispatch? We think it would probably function very inefficiently, if at all.

We would end up relying on our reliability coordinators to use manual intervention, essentially, to meet reliability needs. We do not believe there would be locational pricing, since these are really determined by the economic dispatch that underlies the security-constrained economic dispatch program.

What effect has SCED had on the reliability of the electrical system in your region? In the real-time market, the security-constrained economic dispatch automatically dispatches resources every five minutes to ensure that reliability criteria are satisfied in the most efficient manner.

The NYISO operates a day-ahead market that provides the commitment of generating units, that they will be available to meet the needs of the real-time operations in the next-day market.

One of the things that you asked is if you can quantify this effect? When we looked at the combined effects of security-constrained economic dispatch and the locational pricing, we believe it has provided appropriate market signals, leading to substantial improvement of availability of generating units.

What you have here is a graph that basically shows the reduction in forced outage rates and the improvement of availability over time. You can see, as the markets started to form in the '98-'99 timeframe, you started to see an increase, and then, really, from '99 down to 2001, you've seen a dramatic, essentially, reduction in forced outage, which is an increase in availability.

I think it's obvious that the more available plants are, the more they are available during peak times, the more they're there for reliability criteria.

What effect has security-constrained economic dispatch had on the cost of electric energy in your region, after adjusting for input costs such as fuel?

We indicated before that we have seen significant cost savings since its implementation in 1977. Again, I refer to the 1981 number.

I believe the New York ISO, with some of the additional enhancements we've rolled out here in February, we're basically providing additional enhancements in savings. I think we're going to have to quantify those over time.

It's probably a little bit too early to tell all of those at this point, but looking, though, at just our market and the New York ISO, if we look at the average cost of wholesale energy and our ancillary services, we've seen a decline on a fuel-adjusted basis, on average monthly costs, of about five percent from 2000 to 2004. Obviously, we'll continue to put datapoints on that.

I'd assume that on a one-by-one year, you'd have some fluctuation in there, but the period of 04, which was the first full year of our operation, to last year, which was a complete full year in 04, we've seen about a five-percent reduction.

How can RTOs' security-constrained economic dispatch resources be more optimally dispatched?

The first few bullet points up here are things that I think we've done in our market, and I think the New York platform is really one of the more advanced, and we think these are things that we rolled out in February and that we think could be applicable to some of the other markets, such as the co-optimization of the energy and ancillary services; the shortened evaluation period for real-time unit commitment.

We're looking at bid production cost guarantees to minimize financial risk for suppliers to basically follow dispatch orders, making sure that no one is harmed if they follow our orders for either startup or moving their units from a different set point.

It provides a forward-looking interval optimization of our system, so if we look forward, we're always looking at the least-cost production. Having said that, though, looking at some things that you may want to do, looking forward -- and I think this is the evolution of our marketplace -- one is to improve the regional dispatch efficiency among the Northeast energy markets.

One of the things we've been very successful in, is working with our neighbors over here in New England, the elimination of pancaking, and our seams issues. We've been working on it in our scheduling platform that we've tested here. We still have a lot of work to do on that, but I think there's a lot of capability to look on a more global basis, and I don't think it necessarily requires physical joining of entities.

I think you can look at this on a more dynamic system, if you actually eliminate a lot of your seams issues, and you should actually gain the majority of the benefits provided by a larger regional dispatch.

If you just get rid of your seams issues and are able to look at how you can deal with transactions across your borders, you should get, I think, the majority of those issues right with that elimination.

I think we also have to look at -- and I think Gordon mentioned it before, that we're always going to have to look at better ways to improve our markets. We're constantly going to look at ways to enhance our market platforms and the products we can put out there, and I think they're going to actually help enhance and provide additional economic benefit.

In conclusion, security-constrained economic dispatch has provided significant cost savings and benefits since 1977, when it was first instituted in New York. The New York ISO, in overlaying the markets on security-constrained economic dispatches, has offered significant additional benefits, based on a locational pricing system, and we believe it is an essential tool to efficiently operate the bulk power system and the wholesale energy markets.

That concludes the presentation.

COMMISSIONER BROWNELL: Thank you. Gordon, you're up.

MR. van WELIE: Thank you once again for the opportunity to present to you today. I'll be working off this presentation, the yellow one.

Slide 2 really just gives you an overview of what I'll be covering. New England, I think, has benefitted from region-wide economic dispatch for 35 years, and I'll walk you through the history of this in a moment, but you will see that the implementation of the economic dispatch has changed over time, and I think it has been improved over that period of time.

I'll also talk to the benefits of economic dispatch to New England, which we believe are significant. These benefits have grown since market implementation.

We've identified a number of areas for future improvements, including improved trade and coordination with the New York ISO. I'll skip over Slide 3, because I think we've heard that definition earlier today.

If we look at Slide 4, you can see that we began operating as an integrated power pool back in 1970. It was triggered by the blackout in '65. It took us about five years to form the power pool, but for 35 years, we've been operating in this tightly-integrated basis where unit commitment and economic dispatch were done centrally.

The savings were also driven by economics, not purely the reliability issues, but also the economics of sharing investment in, particularly, generation infrastructure. I'll get to that in a moment, in terms of how those savings were quantified.

System operators back on those days, used experience and offline studies to manually dispatch units to cover transmission constraints. We were doing a form of security-constrained commitment dispatch in those days, but it wasn't done automatically as it is today; it was done manually, offline, and then operators would take the most reactions.

As Mark mentioned, when you have economic dispatch, you then had the basis for evaluating the economics of transactions across your borders to your neighboring control areas.

In Slide 5, you can see that we automated our transactions with New York in the mid-1980s, and in 1990, we moved to the use of a more sophisticated network model for use in real-time dispatch, something called the State Estimator.

This is one of those things that is not universally utilized throughout the industry. It's utilized throughout the ISO industry and some of the larger utilities, but improved modeling makes a world of difference in terms of the results that you get, and so both from a reliability point of view, as well as an economic point of view, this is one of the areas where, if you look at it from a national perspective, I think policymakers ought to take a closer look at this technology.

In 1999, at the same time as when we opened the first markets, we introduced what we called electronic dispatch, which was direct electronic control from our control room in Holyoke, to each of the generators on the New England power system.

You will see in Slide 6 that we began operating interim markets March 1999. We continued with least-cost unit commitment and dispatch.

The following economic dispatch instructions became mandatory. The change really was that dispatch was based on the market offers, not costs, as they had been in the previous world.

These costs generally reflected short-run variable costs of the generators -- fuel, O&M, emissions, and opportunity costs. We continued to manually dispatch generators to relieve constraints. We still did not have the automation to deal with taking into account, transmission and security constraints within the unit commitment and economic dispatch software.

That changed -- and I'm now on Slide 7 -- in 2003, when we moved to implement the markets that we have today. We called it standard market design. It was essentially a copy of the PJM market design.

At that point, the major changes were obviously putting in a binding day-ahead market, using the security-constrained unit commitment. We automated the analysis of transmission constraints as part of the economic dispatch, so, line limits and contingency, modeled optimization software, both in the day-ahead unit commitment and in the real-time economic dispatch.

This gave us several advantages. You take out the potential for human error by automating the process more. You also get a better result in terms of the economic optimization of what you're looking at.

Also during this time, we took a much closer look at all the data surrounding the network model and the modeling of the transmission system. One of the big benefits of the day-ahead market, as opposed to just doing planning, day-ahead, for unit commitment, is the fact that you're creating a binding financial commitment for the generators, which carries through into the real-time market.

You'll see later on when I speak to some of the quantifiable benefits, that what that binding financial obligation does, is increase generator availability. What we saw was generator availability increase by five or six percent over the five or six years that the market has been in place.

That has a significant economic savings in the end. What it means is, you need less generation in the long run to actually supply the demand that's on the system.

Obviously, if you want to implement locational pricing, security-constrained economic dispatch and a State Estimator are fundamental prerequisites to be able to do that.

In Slide 8, I'm moving to some of the savings. Prior to markets, NEPOOL calculated the savings each year, due to central commitment and dispatch. They collected this in what they called the NEPOOL Savings Fund.

What this calculation did, was compare actually dispatch costs, using economic dispatch, with the estimated costs if each utility dispatched its own generation to meet its own load. Each utility would then go and do a somewhat theoretical calculation of what would the cost have been, if I had just used my own generation to meet my own load?

They would obviously try to make it as perfect as possible, and then compare the result against what they actually paid as a result of the economic dispatch. That collection of savings was then the NEPOOL Savings Fund.

We were lucky enough to find the records, so we can tell you that from 1970 to 1977, the estimated total savings due to the regional economic dispatch, were over $1.4 billion in 2004 dollars. We got this from the NEPOOL annual reports.

As I mentioned earlier on, because the owned-load calculations were optimistic and theoretically perfect, they tended to be optimistic, and, therefore, we believe the benefits from economic dispatch are actually on the conservative side.

This number also excluded $364 million from the Quebec Savings Fund, which measured the benefits of the DC tie to Hydro Quebec. During markets, obviously, similar calculations are no longer available.

Most of the generation was sold off in New England. It was not any longer possible for utilities to do an owned-load calculation, but we believe, obviously, that those improvements that have derived over time, would have carried through into markets.

We saw some additional benefits generated by markets. I'll move into that on Slide 10.

Markets: Here we're looking at the benefits generated by markets, as opposed to the benefits, per say, generated by economic dispatch. The point really is that you can't have markets without economic dispatch.

Economic dispatch is an enabling function for markets, so I think it's valid, actually, when looking at the benefits of economic dispatch, to once again look at the benefits of markets as a whole.

What we did was to look at what happened to the average clearing price, NMP clearing price, or I should say the clearing price, because we had two different clearing price methodologies.

We had two different clearing price methodologies during that period of time. In looking at the average wholesale price of electricity over that five-year period, there was a 5.6 percent reduction when you compare 2004 versus the base case year of 2000.

What that translates into, when you net out fuel costs, is the following savings: It approximates to about $700 million per year, and it breaks down into the following categories: About $410 million due to investment in efficient generation and competitive market incentives, so what happened during this period, as a result of markets being established, is that investors built almost 10,000 megawatts of very high-efficiency gas-fired generation, so the average heat rate in New England improved substantially during this period.

As I mentioned earlier, the financial obligations established through markets, helped improve unit availability, so you both have the financial obligation in the day-ahead, as well as the incentive to chase the spot energy price in the real-time market. We quantified that as approximately $90 million.

What markets also did, was to make very visible congestion costs. In the old market, through uplift, and obviously in the new market, through specific congestion costs, we also have uplift in certain circumstances, and I'm sure we'll get into that later today.

What this does is, it puts the spotlight on where to go and solve the problem. Over that five-year period, we also saw about $170 million of savings in terms of reduced out-of-merit or congestion costs.

Finally, in terms of improvements in the frequency response, we quantified about $10 million of annual savings.

Slide 11 just looks at some of the other broader benefits as a result of markets. We've seen a lot of investment in bulk transmission.

We've got about $2 billion -- almost $2 billion in a number of 345 KV projects in four states, having received siting approval, and approximately another $2 billion in addition to that identified in our regional system plan.

I mentioned that we've seen about $6 billion in private investment in new generating resources, which has had significant environmental benefits.

When we look forward at how do we make improvements to economic dispatch and to the markets, obviously what we've got to sort through is what gives us the biggest benefit? Where should we invest our energy, together with our stakeholders?

So we have a fairly formalized process for doing this, called the Wholesale Market Plan, which we publish on an annual basis. What we try to do within this plan, is to maximize the benefits of the markets, while recognizing the resource constraints, both of our market participants, as well as the ISO, so improvements to established economic dispatch, are prioritized with other market enhancements.

On Slide 13, you'll see some of the major market enhancements identified in the plan. If you're interested, we can get you -- and I'm sure you have a copy of the plan, and we could enter that into the record as well.

You can see on that on the list, we have LICAP or capacity market solutions, and ancillary services market, Phase II, where we'll be tackling the issue of co-optimization of energy and reserves; combined-cycle modeling, cold-snap-related changes; improvements in the transaction scheduling on the interface with New York; special-case nodal pricing; demand-response reserves; pilot program, integrating demand response into the day-ahead market; and then pricing of external nodes.

This is not a full list, but just gives you a flavor of what's in the plan.

On Slide 14, I give you a little bit more detail on these various improvements. We have just recently implemented ASM, Phase I. We are working with our participants and expect to be filing shortly with the FERC, a proposal to implement what we call ASM, Phase II, which will have within it, a locational forward reserve market for attracting new peaking capacity to the load pockets, as well as co-optimizing energy and reserves. There's a number of other details, as well.

In the area of reducing seams and improving interface coordination, obviously the establishment of the RTO resulted the elimination of through-and-out charges, but there is still work to be done in terms of optimizing the interface with New York.

We still see potential to improve the efficiency of the regional dispatch between New York and New England. The benefits will be limited by the physical constraints that we have.

We have approximately 1,00 megawatts of import capability from New York under typical conditions, therefore, the efficiency gains will be constrained by the extent of that interface.

As Mark mentioned, we're looking at a number of different mechanisms, including redispatch of the interface or more frequent transaction scheduling. Actually, in terms of the sequence right now, we have focused on the more frequent transaction scheduling as the primary way of trying to solve the problem, to see if we can actually clear the barriers out of the way for market participants to arbitrage the price differences between the two pools.

As Mark stated, I'd agree with him that elimination of the through-and-out charges and improved coordination of the interfaces, will most likely achieve the majority of the benefits of combined dispatch over a larger region.

Slide 15 is one of the areas which has, I think, the greatest potential for New England. That is all about making better integrating demand response to improve the overall utilization of the New England power system.

If you look at the New England experience over the last 15 years or so, we've gradually become less and less efficient in the utilization of our infrastructure. If you look at our load factor back in the mid-'80s, it was in the low 60-percent range; if you look at our load factor today, it's close to 50 percent.

Load factor is really a metric that looks at the utilization or the peak in August, versus the peak in an off-peak system, or the demand in an off-peak season such as the Spring. Just to make this a little bit more real, in Spring, we have a load of around 16,000 megawatts; in August, we have a load of around 27,000 megawatts.

As a region, we have to carry 11,000 megawatts of resources, plus, obviously, the reserves on top of that to deal with essentially what is the air conditioning load in New England. So how one shifts that peak, both at the wholesale and the retail level, is, I think, a great opportunity for New England to make better utilization of existing resources and postpone investment in future resources.

I think this is one of the areas where I see that, in collaboration with the state regulators, we can make significant progress in reducing costs for consumers. We quantify that in the second half of Slide 15.

If you take a cost of capital of around $12 per kilowatt month, every 100 megawatts reduction in peak load, can save approximately $1.2 million per month, or $14.2 million per year, in avoided generation infrastructure investment.

I think that's a target that is low-hanging fruit for the region and it's really something that we need to go after. Of course, that's disquantifying the costs from a generation investment point of view. It does not take into account, all the fuel infrastructure that's needed in order to make those generators run.

We know what the situation is in New England with respect to the constraints in our pipeline system.

On slide 16, we have listed out a number of future improvements to the current economic dispatch. I put this in the research and development category, so there's no firm schedule or project behind these yet.

They are essentially in the research mode. I've listed some of them out there: More optimal unit commitment, based on new optimization models. You've probably heard the phrase, MIPS, used by some in the industry. We believe this would allow for more accurate resource modeling, for example, multiple combined-cycle unit configurations.

We would also like to look at using AC models in real time, to look at the modeling to model voltage constraints, incorporate online stability analysis, and look at multi-interval optimization, which we also believe can produce savings.

Slide 17 and Slide 18 are really summaries of what I have already covered, so I'm not going to go through them in any detail.

Slide 19 is also a summary of the value that's been generated, both by economic dispatch, as well as the markets.

In conclusion, what I'd like to just emphasize, is that we have clearly benefitted in New England from economic dispatch. It has helped improve things, both from a reliability and an economic perspective.

It's integral to the market design, so you can't run markets without economic dispatch, and we believe that both further market design improvements and improvements to the economic dispatch, will result in further efficiencies.

As I said just a few minutes ago, we are planning on improving the interchange with New York as an important part of those plan enhancements. With that, I'll conclude. Thank you.

COMMISSIONER BROWNELL: Thank you. Questions? Don?

MR. SIPE: Both of you mentioned reductions in uplift as a source of savings or perhaps just a gain in efficiency. Do you have any estimate of how much of the reductions in uplift are just a reallocation of costs to more efficiently reflect where those costs ought to be collected, or if there is actually any net sort of total savings to consumers or the system from the reduction in uplift? Very often, uplift is just a reallocation issue, which, admittedly, leads to higher efficiency.

But I'm wondering if, in your experience, you've actually seen that the reduction in uplift is accompanied by a net decrease in costs?

MR. van WELIE: I think that from the numbers that I was quoting, those have been net decreases in cost or efficiency gains for the pool as a whole. If you look at what we were doing as a result of markets, we were taking a lot more care in terms of scheduling transmission outages, for example, to avoid congestion occurring within the system.

Those are savings that are not just a reallocation of dollars. Yes, you are correct, there are other issues. Since you are changing the market rule to better allocate the cost that's been caused, which, over time, will result in a change, one hopes, to the circumstance that's causing that uplift -- and we have somewhat of that situation in Boston, as well, today -- so I think it's a mix of both of those, Don, but I can't separate them out for you.

MR. LYNCH: I don't think we have an economic study that basically -- well, we have some information on locational pricing and on uplift, but a lot of it is reallocation. I don't think we've actually gone in and looked at a specific study to get the true savings.

I do think, though, when you look at the more efficient dispatch, as I mentioned, in the New York City control area, basically taking out all of that uplift that was there and getting it into more specifics, the capability to actually dispatch generation, and looking at the constraints on both the regulation and transmission side, I think this gives you a better pricing signal; it's a more accurate signal, and I do think there are inherent savings in there.

I can't tell you that we've actually gone in and looked at that.

CHAIRMAN FLYNN: This is for both of you or either one of you. Your last slide, Gordon, you have that economic dispatch has improved over time, improving interchange with the New York ISO, as an important part of a planned enhancement. Can one of you or both of you give me a sense of what you are doing now in terms of planing and the type of things that you are focusing on, going forward?

MR. LYNCH: I think we both mentioned the inter-hour transactional scheduling, which was, I think, previously the action known as virtual regional dispatch or something. That is one initiative we've actually conducted simulation on both sides, and the results of that sort of study, our pilot program, came out recently.

Looking at that, looking at the pancake elimination that we did before, we are part of a regional sort of reliability study that's going on. We have included PJM in that, so that we're looking at a more geographical region. We had some joint efforts, even on looking at gas supplies and things of that nature from a reliability standpoint.

Gordon, you may have some others here.

MR. van WELIE: If you go back to Slide 13, Bill, the two on that list related to that interface, are the interregional transactional scheduling and the pricing of external nodes. To be honest with you, I would see those as Tier II enhancements, though, from a New England perspective.

We are focused on a number of bigger issues right now, and so while we're working on those, they don't have number one priority within the ISO.

I think that's appropriate, because, in the scheme of things, the efficiency gains there are smaller compared to some of these bigger issues that we've got to deal with in terms of the capacity markets and the ancillary service market. Those are some of the top priorities.

The other two things that have surfaced just recently in the past year in New England, and, therefore, have a higher priority at this point, would be the issue around uplift in Boston. There's all kinds of reasons for this, and I'm sure we'll get into it later on today.

It's the physical infrastructure that's causing an uplift problem; it's the market rules, and it's how the unit commitment actually treats the combined-cycle units in Boston. The economic impact of that uplift is far greater than the efficiency problem that we've got across the New

York interface. As a result, we're paying a lot more attention to that right now.

The other thing that we've had to shuffle resources and reallocate priorities on, is to deal with cold weather conditions. We learned the hard way in January of 2004, that we are vulnerable to outages from natural gas-fired generation during extreme cold weather conditions, and we want to make sure that we are adequately prepared going into this Winter.

So that whole action plan took priority at the ISO over the last three or four months, as well.

CHAIRMAN FLYNN: From where I sit, both of you should be commended, and your organizations, for communication, because it's gotten much, much better over time. It starts with you two, quite frankly. You are the face on both organizations.

Anything that you do to continue that type of communication, is very helpful, most importantly to the stakeholders and to the ratepayers. Thanks.

COMMISSIONER BROWNELL: Paul?

CHAIRMAN ALFONSO: Like Chairman Flynn, I'll commend you two, ditto on that end.

A question: I think, Mark, you may have alluded to it a bit with now, the experience of hindsight and several years since the proposed merger of the various ISOs.

We'll leave PJM on the sid here for a moment, but just in your New England ISO, any thoughts, assuming the merger had proceeded, given the datapoints you have here, any thoughts on whether these efficiencies or cost savings would have been a higher multiplier?

I think you alluded to it in part, that one need not be physically integrated to benefit from some of these, but any thoughts there, generally?

CHAIRMAN FLYNN: Boy, that's a loaded question.

(Laughter.)

CHAIRMAN ALFONSO: There's counsel in the room, and you can invoke the Fifth at any minute.

CHAIRMAN FLYNN: I second the question.

(Laughter.)

MR. LYNCH: I think one of the issues, and what I alluded to before, was that there are ways to look at your interfaces, the elimination of the pancaking and the other seams issue you may have.

I think you're always going to have somewhat of a limited overall effect. When you look at 30,000 megawatts over in the New England system, you're looking at sort of a peak number, and 30,000 megawatts over in New York, you have 60,000 megawatts and you have an interchange that basically, on a physical limitation, is probably about 2200 to 2500 megawatts.

You really have to think about how much true dispatch and pricing gains you're going to get. You're going to get some, but you're talking about 2,000 out of 60,000 megawatts. You're not going to see the significance of reduction in price that you may see if you could come in and actually have a throughput of thousands of megawatts across certain constraints.

I think some of what we have already done between the New York ISO and the ISO New England, you actually start to see some -- it's going to be done better.

Are there other things that can be put in place? Yes. I don't know if you would have seen anything different or you would have seen a lot of the same. It's sort of the problem that we all struggle with, trying to go back and look at the benefits.

It's hard to recreate what could have been or what may have been, if you didn't take a certain action. Obviously, there was a lot of resource and a lot of capital expended in looking at that, and I assume, for very good reasons, that it did not happen, but I assume that those reasons are still valid today.

To me, you know, I think the benefits are what are they, and what we have to do is basically optimize what we have the capability to do.

CHAIRMAN ALFONSO: You missed out on Holyoke.

MR. LYNCH: Yes, yes, I know.

(Laughter.)

MR. van WELIE: Just some comments from my perspective: I was around at the time, so I can vaguely remember the whole discussion.

We could probably best -- Kurt is smiling, because he was on the other end of the discussion at that time. We can dust off the cost-benefit analysis that was done, but if my memory serves me correctly, 80 percent of the gains that we quantified, were from the elimination of the through-and-out charges, and about 20 percent of the gains were from other efficiencies in the wholesale market, as well as efficiencies from not needing two fully-fledged ISOs to run the broader region.

What we quantified back then was, roughly, you've got about $100 million budget each We guesstimated that we could probably save $25 million from each side.

You know, that's the extent of the benefit that we quantified back then. I think we've collectively done well to get rid of the through-and-out charges, which is the majority of the benefit.

We're working on the remaining issues in terms of the market, and I'm sure we won't get it perfect. I don't think you will get two dispatches on either side of an interface to be as efficient as one single interface.

The issue, really, that I think that one then has to grapple with is, is the time and trouble and investment in trying to put two regions together, worth the benefit that you'll get? You have to tackle a lot of thorny issues on both sides to be able to deal with that.

Quite frankly, I think, given our past experience, I don't think it's a worthwhile investment of everybody's time.

If I look at the situation from New England's perspective, there's more savings to be gained for New England by tackling this demand response problem that I outlined a little earlier on. I think the efficiency gains for New England there, are more dramatic than trying to ensure that we have another hundred megawatts flow across the New York interface.

CHAIRMAN ALFONSO: The only followup is that I know that the issue of uplift here in Boston, building on Don's question, is one that I'd like to engage in when we have our colleagues and our generators in the sector, so I think that can be a useful discussion. Thank you.

MR. BOLBROCK: Rich Bolbrock, Long Island Power Authority, and for the purposes of this discussion, formerly in charge of the NEPOOL owned-load dispatch billing system.

MR. LYNCH: You should have been doing that part of the presentation.

(Laughter.)

MR. BOLBROCK: I'm going to offer some comments on it. I have some comments and perhaps a slightly different viewpoint that maybe Mark and Gordon might or might not want to comment on.

Mark made the observation that it's his belief that locational pricing signals have been working. I won't offer a viewpoint on other than Long Island, but for Long Island, that really hasn't been the case.

As to the transmission interconnections that have been built and enhanced and the current Neptune Project that's under construction, as of a couple of weeks ago, over a thousand megawatts of generation, including the two small combined-cycle plants that were just commissioned a couple of weeks ago, and the larger combined-cycle plant that should begin construction in the not too distant future, were brought about because of reliability issues and because of the criteria and desire to lower the very high costs of power on Long Island.

There really was nothing in locational signals that came into play in that regard. Furthermore, none of the generation, the multitude of smaller units that have been built on the Island, would have been built -- not a single one would have been built without LIPA entering into a power purchase agreement, most of which are for fairly long durations of time.

In that respect, I would have a different viewpoint on whether the locational pricing signals, at least for Long Island, have actually worked.

Both Mark and Gordon indicated that security-constrained dispatch and LBMPs have been responsible for generation unit availability improvements, and, again, I would be my observation -- and, again, speaking for Long Island -- that it had more to do with the way capacity credits were to be calculated and the penalty systems that were actually put into place, if you had an outage, really to do not with security-constrained economic dispatch or LBMPs, but really with capacity.

I'd also suggest that there are other ways that that same result and other reasons that result came about. I wouldn't give total credit, by any means, to security-constrained economic dispatch.

The on-load dispatch and the old NEPOOL savings funds, was never intended to be a calculation of the true value of economic dispatch in New England. It was simply an agreed-upon way that a portion of the proposed savings could be calculated and distributed amongst the members of NEPOOL.

The on-load dispatch was not only how a company would have dispatched its own units, but as part of that very complex calculation, it was how they were able to buy economy service, unscheduled outage service, scheduled outage service, and efficiency service to meet their own load dispatch requirements.

In addition, just to show you how wildly unrealistic the on-load dispatch was, each individual participant could dispatch their entitlements in the generating units that they owned. Many of them had entitlements, pumping storage, for example, and while it would sound odd to you, at the same point in time, some of those participants might be generating from Northfield on-load dispatch, and, while rare, other participants at that same hour, that same day, would be pumping.

There are physical impossibilities in on-load dispatch. I would reinforce what Gordon alluded to, that the savings that were calculated, were dramatically understated. They were probably orders of magnitude greater than what the Savings Fund would show.

Also, Gordon made the comment that the financial commitment was responsible, in large part, to the improvement of unit availability. Under the OMO dispatch system, there was at least a parallel circumstance, because if a unit failed to start or was out of service for any reason, you could not utilize it in your own load dispatch.

There was a different mechanism, of course, but there was a financial implication of not having units start.

Thank you.

COMMISSIONER BROWNELL: Thank you. Kevin?

MR. BURKE: Kevin Burke with ConEd. Since this is a meeting of the Northeast Joint Board, it's natural for the Board members to look at the seams issues between the New England ISO and the New York ISO, but, Dave mentioned in his opening comments, the economic benefits, really, from economic dispatch, depend on the size of the area and the diversity of the area.

So I think that when you're writing the final report, it's important to also consider the fact that there are lots of benefits from improving dispatch coordination with the PJM. Being close to PJM in New York, that's something that would be a natural interest of ours, but I would also say that economic dispatch, as Mark said, is something that started with the New York Power Pool many years ago.

I remember that back in the early '70s, Con Edison signed a contract with Hydro Quebec for about 700 megawatts. It's not only important to look at what's happening in the United States, but also with one of our neighbors to the North.

As we improve the security-constrained economic dispatch, you also have to look beyond, to regions of New York and New England. I think we'll continue to reap additional benefits.

MR. van WELIE: I just wanted to pick up on something Rich had mentioned. I think we need to separate locationality or locational price signals, from the benefits of the market, because I think there were benefits in the New England market, prior to us implementing SMD.

The benefits in terms of improved availability of generation, don't come from LMPs, per se, they come from the fact that generation is no longer able to rely on rate base to cover the costs. They basically have to earn it through the energy market.

Therefore, availability is a big deal. If you're not running, you're not earning money. I think that's the thing that's driven the availability up, not the LMPs, per se.

Another comment from my perspective on LMPs: I think they are tools, rather than the total solution, so I don't think an LMP is going to get a transmission line built. In fact, our experience has been quite contrary to that in New England.

I think it takes a whole lot more energy than just doing a calculation on a piece of software, to get a transmission line built. What the LMP does, though, is point out where the problem is, so that allows people to focus on the right problems, whereas, if you don't have that, the problem can be masked.

Look at the uplift situation in Boston. It's much easier to mask the problem, if you don't have market signals showing you were the costs are occurring.

COMMISSIONER BROWNELL: Thank you. Chairman Adams?

CHAIRMAN ADAMS: I won't revisit the Summer of 2001, even though you've invited us to do so. I will tell you that I was on private practice and billing by the hour, and I got a lot of value out of that particular Summer.

(Laughter.)

CHAIRMAN ADAMS: Gordon, I really want to commend you for taking the lead recently and inviting NECPUC to work with you on demand response, and, I would say, energy efficiency, going forward.

It's probably the biggest untapped resource in New England. My question is, since this is a meeting of the Joint Board, is New York's treatment of demand response resource or lack thereof, as the case may be -- I don't really know -- part of your ongoing dialogue with New York?

If you're moving to a security-constrained economic dispatch regime that considers demand response as part of the protocol, which I believe you're headed toward and which I support, it would seem to me that working with the other control areas, moving forward, would be a helpful step. Is that dialogue taking place?

MR. van WELIE: A couple of comments: I think that if you look at the organized markets, all of them have demand response programs that are similar; they're not identical; they are similar.

I think there's been a fair amount of analysis done on how well they're working and each area knows where they need to make improvements. In terms of the full integration of demand response into the unit commitment and the dispatch in the form that the DR resource is a dispatchable resource and will be treated the same way as a generator in the UC, in the economic dispatch.

I'm not aware of any other ISO looking at that right now. Maybe we have the greatest need right now in New England, so I think, just like we had to solve for the fact that we have inadequate peaking resources in New England, that's not the problem that New York has to worry about, and neither does PJM have to worry about.

So our specific needs -- and this is where regional needs will cause some variation, if we ever get to this nirvana of a standard market design. There will always be some sort of regional difference, because there will be physical differences within the infrastructure that will cause the people there to go off and solve for those problems.

In long-winded way to answer your question, there's no specific discussion between us and New York that I am aware of, on this particular topic, and I guess my advice to New York would be, unless you see a great advantage in doing this right away, let's see whether we could crack the nut here in New England.

You could learn from us, and you can import the approach into the New York footprint.

MR. LYNCH: Just to respond, we do have a fairly robust demand response program in New York. We have a day-ahead market, we have an emergency demand response, which is real-time.

We also have a mechanism called Special Case Resources, that we contract ahead for demand response, basically to be available to us at a certain cost, if we need them in emergency conditions.

We have actually just recently extended a day-ahead emergency demand response program with FERC Orders. We work with a lot of entities, such as Multiple Intervenors over there. They're very key in the municipalities, even.

There's a lot of studies. I think, amongst the ISOs, there's not specific talk, so much as integrating that, something that you would do across borders, but really looking at best practice for all of us. There's a lot of research entities out there that are looking at demand response, the cost of demand response, how you can actually facilitate that.

Some of these are actually looking at the real-time reduction of air conditioning units to be utilized as the spinning reserve type of margin that you can do instantaneously, almost, within a 90-second window timeframe.

There's a lot of programs out there; there's a lot of things going on. I think we're all looking at it, but I do think it's very specific to the load shape that you have for the load availability and also the locality that you have, how you can integrate that into your system and actually integrate that response into your system.

COMMISSIONER BROWNELL: You first, then you, Kevin.

MR. LOUGHNEY: If I could just comment on the question, during the process where were looking marrying the New England and New York capacity markets, there were meetings among the New England and New York representatives that were behind the demand response programs.

There were discussions like that, like what could we do to our demand resources to bid in the installed capacity markets of the different regions. It didn't get very far, and it went away.

But the conclusion was that there was a way to do it. It was just really complicated. There are so many different rules between the two regions and things just don't match up very well.

Again, it was being discussed in the context of how the RAM process was going to be implemented. Once that went away, it went away, but the discussions did take place and there were a lot of people at both ISO staff levels that put a lot of work in, and I think they could probably get it going again.

COMMISSIONER BROWNELL: Kevin?

MR. BURKE: Kevin Burke, Con Edison. I just want to add one point on the issue of demand response. When you're looking at the benefits, when people talk about economic dispatch, they're generally taking a look at the marginal costs of generation.

There can also be some significant benefits to transmission investment and distribution investment, if you significantly reduce the load over an extended period of time. We recently looked back and out over the next few years and looking at what we've achieved over the last ten or 15 years or so, going forward.

We've concluded that in New York City, we probably need another six substations over what we have right now. That's a significant savings in addition to what you might find just from generation and from an economic dispatch point of view. It's something not to be forgotten.

COMMISSIONER BROWNELL: I'm sure there are more questions.

Gordon and Mark, I would ask you to come back after lunch so that you can participate in this afternoon's panel. I know I have a couple of questions.

We're going to break for one hour. For those of you who count, that's 60 minutes. We'll be starting after that. Lunch opportunities are in the mall across the street where there are lots of places or the restaurant in the hotel, which may take a little longer. So be sure you make your timing issues clear.

We'll continue this discussion, get to the panel and then open it up for comments and questions, remembering that we're hear to talk about economic dispatch.

(Lunch recess.)

A F T E R N O O N   S E S S I O N

(1:15 p.m.)

COMMISSIONER BROWNELL: Thank you. We need to keep on time for a couple of reasons, not just because I'm compulsive about it or because the team behind me is going to start kicking me if I don't, but Paul and Bill are planning to adjourn for cocktails at 4:00 and every minute we're late I have to buy. So I was with these guys last night. I can't afford to.

(Laughter.)

COMMISSIONER BROWNELL: We're going to kind of stick to the schedule here.

Bill.

CHAIRMAN FLYNN: Thank you, Nora.

I just wanted to make a real quick comment about this afternoon's presentations. I know there is going to be some reaction to what you heard in the morning in the presentations. And I see in some of the presentations there in there. If the presenters have some ideas, if they want to criticize certain things the way they're going now, that's fine. But I would ask you, if you are going to, to also give us some solutions, possible recommendations on how to do things better so we don't leave it open-ended.

So, if it's in your presentation, thank you. If it's not, if you can include in, or at a later date get it into the record, that would be much appreciated also.

COMMISSIONER BROWNELL: Thank you.

Are there any more questions for the RTO, ISO, CEOs? I got that out.

(Laughter.)

COMMISSIONER BROWNELL: I have one, and I'm deviating from my own rule, but I'm the chairperson and I'm the only person who can deviate from the rule.

Gordon, recently there's been some criticism of the clearing price model and the suggestion that there would have been more savings had you used other models. Do you want to speak to that, please?

MR. van WELIE: I think the debate has been on whether a pay-as-bid approach would generate a better economic result than our current approach. I think the answer is it won't. There's a very interesting paper on this. California commissioned a blue ribbon panel back in 2000. I've got a copy, so I'll leave this with you.

It's titled "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing". I"m not an economist, so I'll give you a very simplistic interpretation of what they said. But, basically, the incentive structure that we have in the current market creates an incentive for generators to bid their marginal costs.

In fact, if you look at some of the base-load units, like the nuclear units, they essentially will bid in at zero. They'll be price takers. That's because they can rest assured that they will get the benefit of the clearing price so they won't get that differential between what their marginal cost would be and the clearing price that will then go towards recovering their capital investment and whatever profit they need to make.

In a pay-as-bid market you have the situation where the average generator cannot rely on that mechanism. So they now have to estimate where the market will clear. They're going to say what's the most expensive unit that's likely to clear on this day or tomorrow, then put in a bid that approximates that situation. What this panel did was look at that. They had, I think, chose some very good reasons why the result of the pay-as-bid auction will be a higher price than the mechanism that we currently use today. People basically always guess on the conservative side. And so, as a clearing mechanism, it's far less robust than what we have in place today.

COMMISSIONER BROWNELL: Thank you. We'll put that study in the record.

Now we're going to ask the panel to each speak for about 10 minutes.

Kevin, we're going to let you go first. We want to leave plenty of time for back and forth. You are free to challenge each other as the audience will free to challenge you -- not you specifically Kevin.

MR. BURKE: I would welcome the challenges because I think that's what leads to a more interesting discussion.

But I'd like to thank you Commissioner Brownell and the vice chairs of the panel. Also, all of the commissioners who have joined us today.

This is an issue which I've been involved in for about 30 years now. Economic dispatch is the way New York has been doing business for over 30 years.

As Mark went through earlier this morning, there have been improvements. There have been a number of improvements. There will continue to be improvements. And, I think, if we got together again in another 10 years, we could still be discussing different ways to improve the model. But I think truly in the Con-Edison era we have seen significant economic savings over the years. I think it's very difficult to put a precise figure on those savings, but we surely have seen significant savings. It's also influenced the way the combination of the generation system and the transmission systems were designed and built in New York State, knowing that you have economic dispatch across the entire state and across the market. Those savings have all gone back to the customers.

Con-Edison had a few adjustment cost since before I came to the company, which is over 30 years ago. All of those savings went back to the customers. We've had the benefits and I can't envision the process being designed any differently. We've been making improvements in security constraint dispatch. We're going to continue to make those changes.

One of the things I thought I would point out is, in some cases, especially in New York City, in addition to the typical security issues that people are looking at from a point of view of reliability, we also have a number of local reliability rules. Over time more and more of those have been added to the dispatch model and the way ISO looks at the model. So, in some case, the uplift has been reduced, as Mark indicated, by those issues being included in the dispatch. We still have some to go.

For example, we have a local reliability rule that focuses on a minimum amount of oil that needs to be burned when the load in New York City reaches a certain level. From a reliability point of view, the concern is that, if there was an issue with an interstate gas pipeline and all of the units or too many of the units were burning natural gas, you might wind up having an impact on the natural gas system, but you'd also have an impact on the electric system. So for many years we've had a local reliability rule. This has been even before we started with the ISO at Con-Edison where, as the total load on the system went up, we would add some burners and boilers that would burn oil. That's an issue that is now a local reliability rule. The power plants follow that and it's going to get into the security constraint dispatch model. It will probably improve the efficiency in which we make changes in the design of the system and the dispatch of the system. So I think those are the kinds of things, but I think we're on the margin of making changes within New York.

As I mentioned before, I think one of the important things is to continue to look at the seams issues between the ISOs and we talked a lot in here today about New England. I'd like to focus a little bit on PJM.

The PJM market is significantly larger than the New York market. There's a lot more fuel diversity there. Coal is on the margin sometimes in -- 25 percent of the time, sometimes 50 percent of the time. If there were some improvements in the way those dispatcher models, which we're working on -- the New York ISO is working on it and the PJM ISO is working on it -- we think we would see some savings there. And that's why I think we need to look more broadly than just New York and New England, but also look specifically at PJM and also at Canada, too, in places where we can wind up getting some benefits of economic dispatch there.

I think it provides the right locational price messages. As you can see from Mark's slide, generation is being built in the parts of New York State are growing where the prices are higher. It provides those indicators not only to the utilities, but also to the rest of the market. I think having an economic dispatch is crucial to the operation of competitive, wholesale and retail markets.

Take a look at the New York area -- Con-Edison and Orange and Rockland. We have 10 different companies that own more than 200 megawatts of generation. I think that promotes a competitive wholesale market. If you take a look at that same 200-megawatt line, there are about 10 different companies that are supplying energy to customers, whether it's residential customers or commercial customers. We're almost at a point where half of the energy delivered through our distribution system will be supplied by somebody other than the utility.

I think this year, when we finish the year, we'll be somewhere between 50 and 55 percent of the energy that we deliver to the customers in our service territory will be coming from Con-Edison. The rest will be coming from the New York Power Authority and the energy service companies. That's been growing and continues to grow.

I think, as we take a look at markets, it's not just the regulated-company markets. I'm looking at the impact on the generators here, but most of the impact on the customers and having a transparent economic dispatch is important for people to be making financial decisions, whether that's the energy service companies or also the customers as well as the utilities who are buying for their customers who are still buying from them.

I think, in closing, if you didn't have the economic dispatch model, the system wouldn't operate as reliably. It would not operate as effectively and we wouldn't be able to continue to promote the markets on both the wholesale and retail level that I think are crucial for moving this industry forward. And I'll take questions.

COMMISSIONER BROWNELL: Kevin, I think we'll wait until the whole panel ends. But one of the things I'd like you, and perhaps others, to come back and comment on are what are those specific seams issues we heard between New York and New England?

For example, they're focusing on some, although we're going to ask them some specifics, too. But, between PJM and New York, it would be helpful to identify those so that we can urge some progress there and get a timetable going. You've been at it 30 years. It seems to me like we're developing markets over about a thousand.

Daniel.

MR. ALLEGRETTI: Thank you very much.

Daniel Allegretti with Constellation.

First of all, thank you for the opportunity to be here and to present. Mindful of the time constraints, I will be succinct. I don't have anything to add in response to the first question for our panel on the benefits of economic dispatch that I think hasn't already been said better than I could by Mark and by Gordon as well as some of the comments that Rich made, too, about the understatement of the savings fund with regard to the real benefits of economic dispatch. I think the numbers there are extraordinary and compelling for the entire country, not just this region.

There are two issues I want to speak to and they do relate to economic dispatch. One is identified on page 18 of the DOE report. It has to do with reliability must run production because it's a big issue, particularly here in New England in the Boston area with regard to what I think is something of a disconnect between the day-ahead unit commitment and the real-time energy dispatch.

In an ideal world you have all of the necessary infrastructure in terms of both transmission and a variety of base-load and quick-start resources that you can come up with a day-ahead commitment that will lead to a perfectly efficient, economically efficient real-time dispatch. But often we have infrastructure limitations that require certain units to be committed in order to meet what we call "criteria" or n-1 reliability to cover the first contingency. That frequently happens at a number of areas such as Boston. It results in large amounts of uplift.

One of the difficulties, and the report points it out here -- it says "When RMR resources are dispatched from the centralized market, their actual operational cost, this is what they are paid, often exceed the market clearing price. They're sometimes paid on the cost plus basis. This can create incentives well within the market rules, but incentives that lead to inefficiencies." The unit owner may have an incentive to seek ways of having the unit committed outside of the day-ahead market for reliability purposes if there's an opportunity to realize a higher revenue. It's perfectly rational behavior, but it can lead, particularly in real time, to an over-commitment of resources, especially where the unit is committed after the day-ahead market during the reliability assessment. If the unit is large or bulky, it may be that there is a need for more commitment of, say, 200 megawatts of additional energy or operating reserves. But the only unit available to meet the reliability need is significantly larger.

Things that we can do to try to address this is to better align the mitigation tools we are using and the price-setting mechanisms in both the day-ahead and real-time market. We need to think about the trade offs in allowing generators who choose not to participate in the day-ahead market by delisting a resource as oppose to bidding their units into that day-ahead, receiving a day-ahead schedule to be committed in real time. There are some important trade offs there. I think they need to be looked at closely.

Gordon, in his presentation, alluded to an important tool that's being looked at here in New England and I think it's been implemented in New York, which is the way that combined cycle units are modeled so that a very large unit might be broken down into component units -- the combustion turbines and the steam turbines looked at separately, committed separately. These are important issues in terms of improving the economic dispatch here. We'll well down the road of realizing enormous benefits from dispatch. These are smaller issues but they, nevertheless, are significant areas where could improve and I think do a better job.

The second area I wanted to touch on in the time available was to talk again about the seams issues. Not to rehash what has been said, but to speak in particular about what has been referred to by the acronyms VRD, Virtual Regional Dispatch, or ITS, Interregional Transaction

Scheduling.

This is an interesting problem. The discussion has really stemmed from a graph Dr. Patton put together when he plotted real-time energy prices and the transactions being scheduled across the New York/New England interface and found what have now been referred to as "counter-intuitive flows." That the transactions that are flowing seem to be counter-intuitive relative to the real-time energy prices. I think before we march down the path of implementing a solution that essentially involves the two ISOs entering into a master trade across the two spot markets, we ought to take a closer look at the problem and see if we have a better understanding of what the underlying cause is of what we're observing.

One of the things that is often said is, if the only tool you have is a hammer, every problem you see is a nail. That's often, I think, for ISOs and ITOs because they live the world of day-ahead and real-time energy markets. But most energy is actually bought and sold in forward, bilateral markets that are much less transparent to the system operators.

I think it's important to understand what are kinds of bilateral transactions that maybe driving the schedules that they're seeing and then comparing to the real-time energy market and what are the barriers to arbitrage in those bilateral markets, even on a day-ahead basis that could drive away the patterns that are being seen. It's easy to take a look at a graph and not remember that there may be bilateral transactions you don't see. There may be operating reserve charges that impact the schedules and transactions that are being entered into. There may be transmission costs that are hidden that are not apparent. Just looking at the real-time energy price only tells part of the story.

When I tried to figure out why aren't traders arbitrating, why are they doing these counter-intuitive flows rather than trying to parse the data and graph it? I have the luxury of being able to walk across the trading floor in Baltimore, sit down next to the real-time traders and ask them why aren't you guys fixing this? Why aren't you putting in these real-time transactions on a day-ahead basis and making this go away? Then I get their laundry list and they have some issues.

One of the biggest is that they need to set their transactions about 75 minutes before the hour. And, for an energy trader, in terms of their day, 75 minutes is a long time. A lot happens in 75 minutes and loads can change, weather can change and prices can change. Something can trip offline. There can be a reserve pickup -- a lot of things can happen. Looking at the energy prices in real time may not be a useful as looking at the energy prices 75 minutes earlier and seeing, in fact, are they counter-intuitive relative to those prices? I haven't seen that analysis.

I think the effect of bilateral contracts is something that has to be looked at -- again, operating reserves and other ancillary costs that may be associated with these transaction. One of the things that I hear from traders it that ATC is not consistently posted by the system operators on both sides. One side says there's a hundred. The other side says there's two hundred. That's a problem across the country, not unique to the New York/New England interface.

The 75-minute interval is something that I know our traders would love to see reduced to enable them to get much closer to real time. Something that would happen for the ISOs under RTS. We think it's better the participants have that. I think the results of the testing done under ITS show just what the magnitude of the risks are. We saw a big price spike due to reserve pickup during the second test in New York and the ISOs sort of discovered -- one of the traders said welcome to my world. A lot can change in 75 minutes. There's a cost when you think one thing is going to happen and you enter a transaction and things go the other way. When traders take that risk, that's shareholder cost. When ISOs take that risk, that's an uplift.

I think that's a really important reason to move along a path of breaking down the barriers and facilitating participant cross-border transactions as oppose to moving along the path of price equalization through a master trade between ISOs under the VRD proposal.

I'm very encouraged by the recent meeting that took place on the 14th of November and by the statements that Gordon and others have made lately that recognize that there is, in fact -- there are some issues with ITS and that looking at ways of facilitating the participant transactions is now something they're very much pursuing and I'm really encouraged by that. And I hope both ISOs will move ahead on that path. Thank you.

COMMISSIONER BROWNELL: Thank you, Daniel.

I think at the end we'll want you guys to jump back in and comment on some of the things that you're hearing.

MR. BOLBROCK: Thank you for inviting me to be here today. I appreciate the opportunity.

We heard this morning that there's a long history of security constrained economic dispatch in the Northeast, both in New York and New England. Because we're in Boston I'll sort of give you some examples for NEPOOL. NEPOOL, as we heard, operated a least-cost security constrained unit commitment and economic dispatch without regard to ownership. Without regard to ownership is important, as David Meyer point out, in the DOE report. That was one of the major issues covered in that report.

The NEPOOL economic dispatch included features that no longer exist in the ISO markets today and I think there are some opportunities to make some progress in that areas.

Just a couple of examples -- first of all, NEPOOL utilizing some sophisticated software used to study and optimize maintenance outages over the year -- the amazing thing was, and it wasn't obvious -- but by moving a single outage, outage for a single unit, there were millions of dollars in production cost-saving achievable. Therefore, they set up a regime where this was a study. Outage schedules were provided to the pool. They made sure they fit in with the reliability criteria, then looked at it from an economic perspective and paid the warranted. The savings were greater than the cost to the owner. It paid the owner to move his maintenance outages. The dollar amounts were staggering. It was surprising. Something that people that dealt with this all their lives never anticipated but very, very large savings that no longer takes place.

Pump storage in New England is always a significant part of the puzzle. The thousand-megawatt

Northfield Mountain Plant has a weekly poundage that was optimized over the course of a week. That no longer is done. In fact, I understand that due to the market system the owner of that facility now has actually added minimum start times, minimum run times and minimum down times to the Northfield Mountain pump storage plant. But this thousand-megawatt facility once optimized over a weekly cycle because of weekly poundage is no longer optimized. So there's clearly opportunities to gather some of those economics.

There are also significant economic transfers over the Northport north harbor 1385 cable. They are not only significant but they were in both directions. Since the inception of the ISO in '99 there have been no economic transfers permitted over that cable. It's currently unclear as to when, this many years later, those economic transfers will be allowed to take place. This is particularly significant because it is the connection of two capacity constrained areas. So there's reliability implications as well as economic implications.

As we heard this morning, the ISO markets have introduced some changes to security constrained economic dispatch, including the optimization of energy regulation and reserves based on bid prices in New York. We heard about the introduction of locational marginal pricing and how SCED is the cornerstone of that. The changes under the

ISOs, though, have also presented some hurdles. One, I think, is not recognized for its significance. The increased complexity of the software leading to long lead times to make changes, to make enhancements and the costs associated with that.

I think we looked at the seams issues and many other issues, including modeling of combined cycle units, things as simple as secondary capacity releases on the Cross Sound Cable -- the list goes on and on. The biggest impediment to getting things done correctly and getting them done in a timely and efficient fashion has been the complexity of the software systems that are in place. That probably would be a good topic for a FERC -- I don't know if you'd call it an investigation or what, but look at where the software was going and what can be done. How much of a problem is it causing in each of the ISOs? Is there a system or some way to get to a more efficient, more flexible, more economic type of software/hardware system?

It's difficult to modify for market requirements. There are often pricing errors and anomalies when software is upgraded. Some of the areas that I think can be concentrated on would be generator-unit representation, including, as Dan pointed out, approved combined cycle modeling, gas turbine dispatch in New York is an issue. LIPA, for example, has a predominate amount of gas turbine capacity in the state, approaching 50 percent of the total gas turbine capacity in the state. This capacity is critical to be in service during the summer periods.

Therefore, in order to do that, and in order to make sure of the highest availability in the summer, we try to maintain those units and watch them number of run hours. There's been a history, including SMD2, of over-reliance on the gas turbines for reserve pickups.

Also an area for exploration would be a reduction in the impact of unit-based point base point dragging. Generators off-base points have lead pricing and dispatch issues. This has contributed to excessive use of gas turbines and requires continued consideration of additional incentives and enforcement mechanisms.

Another area is the optimization of phasing or regulators. Simulating them correctly will improve the efficiency of dispatch. They're currently not being optimized. Improved transactions and dispatch between the market -- this is a very significant area. There needs to be improved flexibility to accommodate scheduling over new winter ties. When interface capability is limited over multiple scheduling node, capability should be allocated, we believe, on the basis of economic value of flows.

Let me just explain that for a moment. Currently, between New York and New England the method that is used in the market system to determine allowable flows on the interface is a calculation that determines what the ATC or available transfer capacity is. The ISOs look to maximize the available transfer capacity. This is significant in that flows on the 1385 cable, if they were allowed to exist, and when they're going to be allowed to take place, economic transfers from Connecticut to Long Island would reduce the allowable transfer capability on the northern ties.

However, if the restrictions are places on the 1385 cable, the result of that would be that actual transfers in real time would be less than they otherwise would be. I would go a step further that while maximizing transfers in real time is superior to maximizing the theoretical available transfer capacity, which historically has well under a 50 percent actual occurrence, what really should be optimized would be the dollars per megawatt hour -- the dollars value of the transfers, if we're looking for a really economic dispatch. That's somewhat more complex but it can be done and it's something that I think should be taken a look at.

Also, Dan had mentioned scheduling lead times as an issue under the pools. In real time, 30 minutes before the hour is the operators with "incremental and decremental costs." Transfers would flow in one direction or the other

-- economic transfers, economy transfers and savings would be split. Thirty minutes is now 75 minutes. I would second what Dan says. This is an eternity. This is a lifetime for this kind of transaction.

The 1385 line -- the Northport to North Harbor Cable, which has been in service for a little over 35 years now, I think is a good example of some of the issues that need to be addressed. When Cross Sound Cable was put into service, it took a while to get the ability to have multi-party scheduling on that cable. That was implement in June 2005.

In theory, this should have enabled other controllable ties. The software to be marginally modified for very rapid changes to the software to allow scheduling on other controllable ties such as 1385 or such as the Neptune Table, which is, as I mentioned earlier this morning, is under construction.

On the NEPOOL, there were significant economic energy scheduled of 1385 in both directions, accruing to the benefit of the ratepayers in both Long Island as well as Connecticut. After introduction of the ISO, the schedule was set to zero for 1385. I can't sit here today and tell you with any certainty when we're going to be allowed to schedule on this facility, but it's no earlier than sometime next year.

The introduction of a New York ISO controllable line scheduling software in June 2005 should have facilitated time in the economic scheduling over 1385 as well as any new external transmission facilities. The ISOs continue to delay implementation, impeding reliability as well as market efficiencies. The inability to integrate New York's internal the market on a timely basis is one of the remaining seams issues that suggest that further efforts have integration or consolidation of dispatch systems may be warranted.

One way to eliminate in a timely fashion the existing seams as well as to prevent new seams from cropping up in the future would be to take another serious look at a single system -- a New York/New England single system economic dispatch.

COMMISSIONER BROWNELL: Thank you.

Michael, we're going to take a break after you and have Mark and Gordon respond.

MR. CALVIOU: Thank you for the invite, Nora, from yourself and the chairman and commissioners to speak this afternoon. My name is Michael Calviou from National Grid.

Like many of the speakers, I think most or all of the speakers today, we believe that economic dispatch is fundamental to the current electricity market and helps deliver a significant benefit to the consumers. That's not an area of contention.

I think it's an interesting debate about how big a region should economic dispatch extend over. I think, in theory, economic dispatch has more benefits to the bigger region it goes over. We've seen in the past where consolidation and integration of economic dispatch over larger and larger regions has customer benefits. The bigger region we do a dispatch over the bigger customer benefits you tend to get.

In the case of New England and New York, it might suggest while perhaps we should be having another whirl at doing some sort of combination, however, I do agree with previous comments. I think most of the benefits of the combined economic dispatch with New England and New York can be delivered by seams elimination and other improved coordination. The costs and all the issues being raised of doing a complete combination and maybe moving to a single market structure is probably not warranted. I think, though, it is worth talking about. What some of these improved coordinations and seams elimination activities should be.

First of all, I will pick up on the issue of the interregional transaction scheduling that Dan has spoken about and, of course, has been mentioned. It's fairly clear that in the current market there is still a seam between New England. There are an economic outcome power does seem to flow in anti-intuitive ways as Dan has discussed. There may be reasons for it, but that you would hope in an efficient market, hopefully, the power would flow in the right way and you could see when there's a price differential between you and New England. You ought to see the whole capability of the transmission system being utilized. Very often that's not happening at the moment.

This was recognized several years ago. The first answer was to remove the pancaking through and out charges, which we did. Everyone has agreed that it's a good thing, but it hasn't seemed to solve the problem. We're still getting anti-intuitive outcomes. The idea of virtual regional dispatch now called interregional transaction scheduling has been looked at.

While I do support the idea that we should let the market do as much as possible and that there are improvements that transaction scheduling, particularly reducing the 75 minutes, would lead to the ability of the market to more efficiently trade in arbitrage. I'm concerned that because we can do these things that we shouldn't be looking at some more comprehensive solution and a backstop solution as well.

Ultimately, it seems to me the ideal model we should be looking for is what would we get if we were doing a single dispatch between the two regions. If we were doing a single dispatch, we wouldn't have this artificial seam and there wouldn't be this need for arbitrage between the two areas. So that the idea that we can -- the isolation of any raw number is misguided. Therefore, I do support improved transaction scheduling, but I think the ISOs should press on with the idea of a re-dispatch by the ISOs, resulting in improved utilization of transmission capability between New England and New York to force greater convergence and remove some of these anti-intuitive outcomes.

It may not be the highest priority on the list that Gordon and Mark were talking about, but it is important and I think there are customer benefits being left on the shelf there and I think that should be addressed.

A second specific improvement that I'd like to suggest is one that hasn't been discussed so far and one we've only started thinking about quite recently. At the moment New England has 2000 megawatts HBDC interconnected to Quebec. The U.S. Interconnector Phase 1 and Phase 2. Phase 2 has a 2000 megawatt limit. In practice, most of the time, it's limited to about 1200 megawatts because of constraints further down the system, particularly in New York and PJM. This was conditional of Phase 2 when it was constructed that, effectively, Phase 2 capacity would take the strain from these transmission constraints further into the eastern interconnection. At the moment, I think, particularly quite often it is the New York constraint -- the interphase constraint is the constraint limiting those loads to 1200 megawatts at the moment.

I think that maybe with better coordination between New England, once you get increased utilization of that link and produce benefits for the entire region. For example, Quebec, which exports into New England, also exports into New York and that export comes out on the beneficial side of constraints in New York. The engineers in my company tell me that if, under most system conditions, if you would reduce, say, flows from Quebec into New York by a 100-megawatts, there's probably only something like a 3 to 1 benefit. So a 100-megawatt reduction connect to New York may release up to 300 megawatts of increased capability on the Phase 2 interconnection from Quebec into New England.

Now I don't think this is a straightforward proposal. It will require coordination, improved coordination between ISO New England, the New York ISO and Hydro Quebec. There will be a number of complicated transactional issues to resolve, but I think it is one worth pursuing, particularly because clearly in current conditions concerns about gas market shortages is the potential way that we effectively, at the margin, replace gasified generation in the northeast of the U.S. with increased imports of hydro power from Quebec.

This is, again, an idea that I think should be pursued with the both ISOs and we're certainly happy to work with them to work on this idea to see what can be delivered and I think it probably fits in with some of the other ideas which we were talking about in terms of, including the coordination and the seams between the two markets.

One other issue I'd like to talk about in terms of dispatch. I think several people today have talked about economic dispatch and revisional pricing has increased transparency. Transparency is good because it helps everybody understand what's going on. It helps the markets be efficient. It helps customers understand that they're going to get a good deal. Though, I agree economic dispatch does lead to greater transparency, actually in the markets we have in New England and New York, there is actually a major source that is actually blocking transparency, and that's the fact that key data, such as the generator bid data in the markets isn't released until six months to market participants.

This restriction -- this sort of six-month lag in the release of data, I think, was put in place when the markets were conceived probably as a regulatory protection. I think there was concern that there might be collusion between generators and therefore that was put in as protection and has been left there because no one really looked at it again. But I think in practice and there's good market experience, both in the U.S. and around the world, that actually more transparency could be -- the fact that this data isn't being released is probably hurting buyers more than seller.

We see markets around the world -- places like the U.K. and Australia where this sort of bid data is released on the day or the day after the market outcome. There doesn't seem to be any problems caused by that. They have the same market-monitoring type regimes we have here. The market monitor regimes we have in the U.S. are pretty sophisticated now, therefore, some of the concerns maybe should have gone away. There seems to be some transparency will provide a number of benefits, both in terms of giving consumers greater confidence in what is going and understanding dispatch outcome and also allows market participants to identify where there are inefficiencies.

We've talked about particular cases. If people have more data and have more to work with, they'll be able to identify where there are inefficiencies and either solve them by trading activities and more transactions or add to the shopping list of stuff that we want the ISOs to address.

These are just a few of the, I think,

improvements that could be made. I think there are other improvements, particularly things like the ancillary service market's Phase 2 in New England as well.

My final comment is just to note, I guess, the fairly obvious point that economic dispatch is a security constrained economic dispatch. The amount that the most economic generation can be dispatched is limited by constraints. One of the key constraints is transmission limitations. I guess it's fairly obvious that, if there were increased transmission capacity, increased transmission investment, that would leave the ability to do further increased of economic dispatch and I commend solutions which will enable increased transmission investment to take place.

One idea I have heard discussed in at least theoretical circles is the idea making transmission a dispatchable resource, dispatchable transmission and sort of expanding the merchant transmission concept. Why don't we make transmission the platform for the market actually part of the market? I'll suggest that's probably quite a bad idea. I don't think anybody's suggest it here, but in case anybody did --

(Laughter.)

MR. CALVIOU: I was just going to say it's a nice idea for the academics to discuss, but I think in practice we want a robust transmission system to actually enable robust economically-dispatch generation to take place.

Thank you very much.

COMMISSIONER BROWNELL: Thank you. I'm pleased that you brought up the infrastructure issue. I'm surprised it hasn't been a greater part of the discussion. Certainly, that's more meaningful for some states than others. So thank you.

Gordon and Mark, do you want a chance to comment on what you've heard.

MR. van WELIE: I was sitting here thinking about how to do this briefly because each of these topics have taken up many hours worth of discussion in various workshops and NEPOOL market committees. So they're all complex problems.

In most cases there are more than one thing that needs to be done in order to solve the problem. So what I'll do is touch on these things on a very superficial level. But, if you want to get into the details of how to solve these problems, I think we would have to dedicate a lot more time at later point in time in a different venue.

Let's start with Michael and work backwards. What is interesting was the clear opposite position that both Dan and Michael have on the ITS situation and I think that was quite informative to kind of see some of the debates that take place within NEPOOL. You often have two parties on either side of each issue. Really the only way to work through that is to kind of figure out -- for the ISO to figure out what it thinks the solution is and then take that through a very rigorous review process, through it's stakeholder process.

In the end, I guess, the FERC gets to decide what the final answer is when we can't resolve it ourselves. I think, though, on ITS where we've come to is that I think the first point of attack is to try and reduce the time window on the transaction scheduling. That ought to be our first focus. Then, to Michael's point, we may be back at the redispatch solution if we see that doesn't solve the problem. So I think it's a two-step process and that's how we're seeing it on the redispatch of the New York system in order to accommodate a greater flow back through New England. That's an interesting issue, I think, that will require coordination between the two pools.

I have a question for Michael, though, which is why he thinks the market wouldn't be able to do this?

MR. CALVIOU: I think the market can do a bit, but I think the main thing the market can't do is actually deliver the increase in available transmission capacity over the Phase 2 link so the market can deal with the transactions. But, at the moment, I think the determination of what the Phase 2 capacity is done based on what system additions are and I'm not sure they've got the dynamic process to enable that to be performed and the transmission constraint to be relieved.

MR. van WELIE: So the limits on what we import across the tie are more to do with protecting for the loss of the biggest unit in New England. In this case an HDQ tie. It looks like a big generator.

MR. CALVIOU: In particular, when you loss 1200 megawatts or more on that tie, that will be made up with power flowing. A lot of it will come from the West where there are voltage constraints. So, for example, over each interface in New York it could take in -- if that is too big, then the power flow over the interface can make it more constraint -- and placement. That's what causes the limit. Voltage constraints in either New York -- it has to take into account if you loss the big lot power flow can make it up and go over those constraints.

MR. van WELIE: I was wondering where you aware of the fact that we have, from the ISO New England point of view, inserted the request into the interregional planning discussion to take a look at this very issue, which is how do we relieve some of the constraints within PJM and New York that will allow us to flow more power across that line? That's one of the tasks before that interregional planning group. So what I think we want to do is take a look at the results of what they bring back and then take the next step that we need to.

MR. CALVIOU: Just to sort of finish off, I think that there's probably two aspects -- the short-term and the long-term aspect. I think in the long-term there's definitely something that needs to be done under the interregional planning process. I think that is a longer term issue of can investments be made, say, in case we have a conversation in New York to actually help. We really support that happening. I'm not sure the interregional planning groups will be looking at these shorter term ideas and that's the idea we're talking about. But I agree.

MR. LYNCH: I do want to caution, too, that I do think there are some economics here besides just reliability and the -- is talking about this. I think you have to study this on a much more global basis. It's an interesting position you've put out there from a reliability standpoint that sounds right, but I do think there are economics and there's going to be winners and losers. Market participants would have a lot to say on how they take positions on different sides of the border, of whether this is a benefit or not. When you look at it, I think there is an issue here that needs to be studied and addressed, somehow analyzed and look at how we could lay this out.

MR. van WELIE: On your last point, Michael, basically the issue of the NEPOOL basic information policy, I think we're open and I think we've signalled that we're open to re-looking at that. The best thing to do is to raise it at the appropriate NEPOOL committee and let's take a look at it again. I think it will become a matter of when do we schedule it through the stakeholder process because there are many competing initiatives that are taking up -- Eric's cringing in the back there. He works for Central Manpower and is the vice chair of the Market Committee.

(Laughter.)

MR. van WELIE: I think that's something we put into the hooper along with everything else and we take a look at it. There's no problem with it from our side. I agree with you. More information is better.

To Dan's issues, I think we've kind of covered the ITS scheduling. Let me just briefly comment on uplift, which I know is a problem for suppliers because of the difficulty of hedging that.

If you look at the situation in Boston, it's a complex problem in the sense that the problem manifest as uplift but it's caused essentially by several things. The first is the inadequacy of the physical infrastructure and there's kind of two parts to this. One is the transmission system into the Boston area has needed strengthening. Some strengthening has been done, so the problem is somewhat alleviated and we're obviously in the process -- and NSTAR is in the process of completing an upgrade into the Boston area by the middle of next year.

We also have some physical limitations in terms of what's available to be dispatched in the Boston area. That's one of the reasons we want fast-start peaking resources in the Boston area so we have more flexible units and where we can commit less in order to deal with some of these reliability issues. So we've got some market initiatives underway to address that.

The modeling of combined cycle units is an issue that we spoke to earlier on. And then, ultimately, the market rules and the incentives created from market participants around the market rules. So all of these things have to be looked at. We've had several workshops on this problem and we've got forward motion on most of these aspects that will take some time to resolve all of them.

To Richard's points, I think I've mentioned we are moving forward, both in terms of pricing and external notes and the 1385 cable. The 1385 cable is kind of an interesting thing. There was a history before I was around, I'm sure. But there have been two issues there. One has been the actual physical condition of the line and having the two transmission owners on either side of that interface move forward with repair of that line.

The second issue has really then been how does one put into place both a pricing note on that line so that you can value the trade at that point and how do you set up the transaction scheduling? We've got an interesting situation to deal with because, essentially, there's a trade off. When the New England and New York interface is constrained, 100-megawatt flow across that line actually will decrease the availability of the upstate interface by 300 megawatts. How one deals with that is fairly complicated. This is something we've got to work through and create a solution for. I think it's time and application of resources.

And I think I covered everything.

MR. BOLBROCK: Phil Padore, on my staff, is now MPCC. Is that right? Phil, we tried to figure a way to do that about 10 years ago when we didn't have some of these market impediments to do that. Michael is correct. The challenge is how to properly allocate the costs. The savings are there. The pie is bigger but how do you allocate the costs that go along with it?

A similar experience would be we had proposed sometime in dealing with this West Connection situation to send power through Cross Sound Cable across to LIPA. A system which would be reinforced with the Cross Sound Cabel and the then up the 1385 line. The market rules don't allow that. In fact, some people said it couldn't be done. When we were asked to do a test, I said I have a right to do a test, simultaneously have a flow of 50 megawatts from Connecticut over Cross Sound to Long Island and simultaneously 50 megawatts back up into Connecticut over 1385. The way that should have been done and the way it would have been done under the pools was to just change the flows on those lines by 50 megawatts. The way we had to do has actually increased generating by 50 megawatts for the one transaction. That had to be done at times. One, a change in generation wasn't going to be an issue and at additional cost. So there are a lot of these kinds of opportunities utilizing the transmission infrastructure in ways that I think will have very large paybacks. I certainly agree with Michael's approach.

COMMISSIONER BROWNELL: Thank you for your suggestions.

Mark.

MR. LYNCH: May I throw in just a few comments here and sort of reiterate a couple of things here?

First, Kevin's concern about the PJM and our seams issues. I don't think this is the forum to go through a lot of those issues, but, indeed, we are working with PJM and the groups down there to basically look at those issues. There is no doubt we are not in the same position as we are with New England. There's a lot of work to be done down there and that's an issue we do have on our plate. And it's something we're actively looking at, but we have not made as much progress as we have in New England and it's something that we need to address fairly quickly so that we can reap some of these benefits.

I think, in looking at the inter-transactional scheduling I think Gordon said it correctly. There's a lot of things we need to look there. You bring forth some very good ideas and we need to analyze, basically, and address as we move forward here -- we're in the pilot stage. That means we're in the very beginning. There's a lot of things we need to look at. I think there is opportunity there and I don't think they're going to apply in some cases here, but I think we can apply it up through Canada and PJM eventually in the future.

Rich brought up a few things. There are a lot of things we are working on as far as utilization of the combustion turbines, looking at applying the proxy bus solution as we have in the Cross Sound Cable, the 1385 cable and making that available really across the entire New York ISO system -- sort of making a standard there where we can actually utilize this. It's things that we're working on. We realize that there's a pressing need here and we're working through the issues. Hopefully, this will come to a theater near you soon.

I think on the other issues, Mike, we've sort of touched on those with Gordon. I think there's a lot of things that eventually we're going to have to look at. It is an amount of resource, time and priorities. I think these are all good ideas and things we basically need to keep our eye on and sort of move forward with, but always look at these things as new enhancements and things we can actually do to improve the overall regions.

COMMISSIONER BROWNELL: Not today, but maybe we could get together and think about ways that we could prioritized some of these solutions because I think there are, in the stakeholder process of which I am a notorious critic, we're not as good at prioritizing things as we might be in that everything gets debated equally where we could have some shorter term fixes that could be implemented without reallocation of huge amounts of resources from other priorities. So maybe we can get together on some of the specifics.

MR. LYNCH: I actually enjoy that forum.

COMMISSIONER BROWNELL: Bill and I are very, very good at helping people work through seams issues. We'll be happy to call PJM and convene a little meeting to talk about those. Right, Bill? Okay.

MR. LYNCH: Thank you for your help.

MR. van WELIE: Nora, I was going to say that what would be useful, if you would have such a discussion, would be to have the equivalent of a wholesale market plan from New York and PJM. What will happen is each region will tend first to look at what is the highest value for the activities within its region. When it says optimizing from a regional perspective New England is not going to look at what's the optimum solution for New England, New York, and PJM. It would impossible for us to do that. So you'll see that our priorities are driven with respect to the value that we created within New England. I'm sure that, if New York were to do it, they'd come out to the same thing. Then it's a question really of would you folks sitting around the table agree with the way we've stated the priorities or do you think we ought to shift the priorities in that identified list? In order to have that discussion I think you'd need that as a starting point.

COMMISSIONER BROWNELL: And we can add Paul and his colleagues as well.

Steve?

MR. CORNELI: Thank you very much.

I first want to comment that while the Energy Policy Act is a big document, obviously, one of the good things is bringing this group of people together. I'd like to see more of this because the wholesale market, which we all struggle with and the retail markets, which the state commissions, in particular, struggle with, really need to work together so that power can flow from producers like us through suppliers, transmission owners and customers, whom you all represent and everybody can benefit from a competitive process. It's a great opportunity to all get together and talk about some of these important things and I appreciate it very much.

I'd like to start by stepping back and looking at the whole concept of economic dispatch and really think about the national scope that is going on here and what we can learn from the discussion today about the national scope. There's near universal agreement here today so far, at least, that security constrained economic dispatch has created a large savings for customers.

And really, as I see that, there's three key elements of that. The first is a highly detailed capability of modeling, a large piece of the transmission grid that covers multiple utilities service territories. The second is uniform and universal access to network service or some related concept of transmission service. The third is independent administration and operation of the actual market and the dispatch that's based on the modeling and the characteristics of that transmission system. Those are things that we sort of take for granted in New England and

New York and the northeast because we've them for so long. But a lot of the discussion today has been about the details of making those issues work. I think those three key factors are something we should all be pleased to have in the northeast and eager to improve.

Let me talk a little bit about where we're at and what might be improved from a fairly high level in terms of economic dispatch in the northeastern markets. First, it seems that there were probably three main expectations or hopes that the designers of economic dispatch and economic dispatch-based markets had in mind a few years ago.

First was to minimize the variable cost of converting fuel or energy carriers into power without violating reliability requirements. Second was to provide a framework for an efficient energy market and the third was to use that market to send price signals for maintaining and adding and attracting new resources, whether for generation demand response or transmission. That's really, I think, if you go back to the initial discussions about LMP markets and what they were supposed to achieve, what people expected.

How did they perform? I think we've heard and seen that the minimizing of variable costs has been successful. You've heard various estimates today of maybe from 50 to 100. That range of a million dollars per year in short run savings simply from economic dispatch. This isn't a market. As Gordon pointed out -- I think Mark as well -- there's been much bigger savings from actually using a market based on economic dispatch and we certainly see these in recent studies, whether it's the ISOs own studies of savings or the product that SERA came out with recently that announced $43 billion of savings over five years in the eastern part of the United States or the Global Energy Decision study, which had a $15 billion savings in the northeastern part of the United States over the same period.

These savings come from the cost minimization efficiency enhancement, the risk management and the innovation of markets that are based on an economic dispatch system, and a big part of this is creating inventive technologies, whether it is the new technologies like clean coal, advanced demand response, merchant transmission or more efficiently planned and constructed regular transmission. All things we're all interested in.

So the performance has been good, but a lot of the performance really depends on how the market itself is working. Let's quickly think on how the actual energy market as oppose to simply the older economic dispatch itself seems to be working. Our view is that the market has been fair to good and it's getting better. There are some problems. To get into those problems, we need to get down into details a little bit. I think probably the biggest issue, from our perspective in terms of how these energy markets are actually working, is that not all of the security constraints are reflected in the security constrained unit commitment and the security constrained economic dispatch.

If you look at both the ISOs presentations, you can see a list of improvements that have been made and additional improvements that need to be made to correct these problems. If these constraints aren't in the market software and the services need to be provided to keep the lights on and are typically provided through what is called out-of-merit dispatcher resources, which created additional uplift charges that are just kind of dumped like a tax on suppliers or on customers. Nobody can really do anything about it except to pay.

They often suppress or distort the market prices that generators and other market participants get paid in the process. So this uplift problem needs to be resolved and needs to be resolved by making the actual market software more comprehensive and covering security constraints that are actually out there and modeling the system more accurately in dispatching and pricing power.

Another thing that we've seen that has been very difficult in these markets to establish what you might call scarcity prices. Prices that get above the short-run variable cost of production in times of reserve shortages or scarcity, and to distinguish these higher levels of prices from the abuse of market power. In short, it's been difficult to get prices quite right.

This leads to a third big issue that in our view is very important in terms of making these markets work. Even if you get prices right, it's very important to allocate the prices properly. I'd like to give two quick examples of the challenges that there have been.

First, the uplift that has been created, especially in southern New England associated with not putting all the reserve requirements into the security constrained unit and dispatch, and instead having them picked up through various kinds of dispatches that are paid through something called "operating reserve credit," which is a form of uplift. It's uplift that really shouldn't be there if we had a good, perfectly designed market.

This uplift, until recently, was taken and was actually allocated to people who were selling power or buying power in real time that was different from their day-ahead market positions. What this did was it made it very difficult for there to be virtual trading between the day-ahead and there real time market, which is something that's designed into these markets to make them work better and to make them more efficient. So we had an allocation of uplifts that prevented efficient trading and this was actually -- the allocation part was fixed earlier this year, an example of the kind progress that has been made.

A second example is, to the extent that there are price signals for building new resources and maintaining system resources, they're not always allocated to the entities that have the strongest incentive to actually go out and do something about the problem, like contract with somebody to build a new generator or contract with somebody to maintain an existing generator in a way that minimizes the cost for customers. Sometimes these costs are allocated to people who have difficulty or actually no interest or ability to contract for new resources.

Let me move on quickly and superficially, perhaps, to the last question of do these markets -- have they performed well? In terms of sending the price signals for the resources I think it's clear that they haven't. They have pointed, like Gordon said, to where the resources should be put, where the problems are, but they haven't necessarily produced enough revenue or expectations of revenue to attract the investment that we need, whether it's in new generation, new demand response or new transmission. Instead, where these are happening they're largely happening in response to RFPs and contracting opportunities that have been put out by either load-serving entities, state agencies or power authorities or other sort of non-market approaches.

It's clear without getting into areas we don't want to talk about today that there's a growing consensus that there needs to be some sort of refinement or revision of the current capacity markets to address this problem.

So let me move on and talk about what we would do if there was a blank slate. The kind of key take-aways, from our perspective, are. There's really three. First, we should include all of the constraints that are relevant to the dispatch of the system in the actual market software and market pricing mechanism and in the prices and we should pro-optimize markets for reserves, ancillary services and energy, much as New York has moved to do recently. Second, we should build in an effective broadly acceptable and supported resource adequacy and capacity market mechanism. Third, we should make sure that we allocate the costs from these market mechanisms to the entities that have an incentive and an ability to take market actions that will react to the price signals.

With that, I'll stop and take any questions. Thank you.

MR. HORAN: Thank you. My name is Doug Horan from NSTAR Electric. I have some slides I've distributed and I'll organize my comments around those.

It's always helpful to start -- to let people know the perspective from which your comments come. The first couple of slides talk about exactly that and the remainder of the slides identify a couple of issues that we think are significant.

If you look at the first slide, it shows NSTAR's service territory. As you can see, we serve much of eastern Massachusetts. But I think the two points that are important here are, first, 67 percent of the NEMA load is in NSTAR service territory. So, obviously, issues that relate to NEMA are very important to us.

The second point is that NSTAR has divested all of its generation. We own no generation. We have no marketing arm. We have no for-profit activity in the generation market. We do, however, continue to supply power to a substantial number of our customers -- well over 90 percent by count, over 70 percent by mode. In the Massachusetts structure we're the one responsible for providing energy to those customers.

If you'll look at the next slide, you see the source of our concern or our perspective on the energy market issues. This happens to show the rates we charge our customers and the delivery rate, which is obviously a concern to us, is flat and has been for 10 years. The energy portion which we bill to our customer is large. It's volatile and right now is very large in comparison to the rate that we charge. If our base rate is 6 cents, our energy rate is about 12 cents, given current prices.

From our perspective, as we're out buying in the market for our customers, our objective is simply to do the best we can and to pursue customer service. We're very concerned about the impact the energy market has, both on our customers, on the regional economy and frankly on our reputation. Because while I can look at this chart and distinguish between the energy and the base portion, customers don't do that. They just see a large bill from NSTAR. So the perspective that we've had for the last several years has been one of fairly aggressive pursuit of customer interest in the energy market.

The next slide is a quick summary of our perspective on security constraints dispatch issues. It's been mentioned several times that there's a long history of central dispatch in New England and it's true. There is. But, of course, when markets came in some years ago now there was a significant change. Because prior to that dispatch was based on cost. It's now based on bids. The dispatch results are going to be efficient only if the bids are sound. That is to say if they have a relation to marginal cost. So while we've had 30 years of experience with central dispatch, the important point is we've had much less experience with bid-based dispatch and that give rise to much of our concern.

NEMA is an area that has highly concentrated generation ownership. Some 70 percent of the generation is owned by two entities. As a result, we tend to be very concerned about exactly how the bids are created and whether or not there's any market behavior we should be concerned about.

If you look at the next slide, it shows the NEMA area. What this shows is the NEMA load and also the history of transfer capacity into NEMA. Generally, the northeast Massachusetts area has been viewed in New England as a constrained area. Northeast Massachusetts and Connecticut are viewed as constrained areas. When you look at this what you see is there's been a steady improvement of the transmission into the area. We've added, through a series of smaller projects, substantial capacity and there is a large project underway at the moment which will be finished next year which will add about 1000 megawatts of transfer capacity.

The point of this is, if you combine the resources and the transfer capacity in this area, even now, it's in excess of peak load by 40 percent. When the new line is in place, it will be in excess by 60 percent. So with a high level, if you think about constraints as being driven by transmission capacity, you would assume that the constraints should be small and diminishing. In fact, that's not the case. As has been discussed before, in addition to the sort of large, high-level transmission issues there are local constraints, contingency security analysis that need to be done in the Boston area, which results in uplift charges.

The chart which talks about unit flexibility and its impact is a chart taken from the ISO independent market monitor's report in 2004. What it's showing is the amount of capacity that, in fact, ISO calls for that it needs in order to meet its reliability concerns and then the amount that it gets for a variety of reasons and the amount it has to take from market participants.

You can see in the bar in December the amount that was sort of beneficial was about 60 megawatts. The amount that actually was required or turned out to be taken was 450 megawatts. In a sense, that's a measure of the degree of improvement opportunity in terms of uplift charges. One of the reasons this comes out in our view is because of unit inflexibility, meaning, ISO needs power for 3 hours and the unit says its minimum is 10 hours. If they need 200 megawatts and their minimum is 700 megawatts, the question, I think, that is highlighted on the next page is sort of what's the impact of that?

You can see in 2004 the total uplift costs were in the range of $80 million through October, which is all the data we have. It increased to 130. And, if that continues, we project through the end of the year, to $150 million. I guess the point of that is twofold. One, it's a big number. That's about 10 percent of the total energy cost in NEMA. This is not a small problem or a small aspect of the market. It's a very large one.

The other thing that is notable is the increase. Because if you think about the fleet of units hasn't changed substantially. The constraints and the transmission system haven't changed substantially. If you have a doubling of uplift costs, then you have to think about whether that's related to sort of structural issues or whether that's a commercial decision in terms of how restrictions on the unit are going to be placed.

If you look at the next page, again, our concern is, to the extent that this -- I'll call it a behavioral issue because again we do have a very substantial amount of market power in NEMA. The solution is closer examination, more audits, rules that more clearly limit the amount of inflexibility that generators can put in their units. It maybe that some of this is structural and not behavioral in the sense that units are what they are. Some units can't ramp, can't be called for in a short period of time and, again, if that's the case, in our view the solution is on the capacity side of the market you need a better price signal that's going to call for flexible units. You're not going to fix this problem with broad-based capacity payments. You're going to fix this problem with targeted capacity payments. That's the work that's putting together the forward reserve market is certainly in the right direction. That's what will help solve this problem.

What I've talked about to date has been the uplift issue. If you look purely at congestion the different in marginal costs between zones,there's also, in our view, potential for a significant behavioral factors that drive congestion higher than it needs to be. As an example, if you're in NEMA and you know that you, for security reasons, are likely to be called, you may very well bid high in the day-ahead market and then get called in the real time market. The effect that is to increase congestion costs.

Now, as we look at the market data that's available to us, we find some units that over a period of time during 2004, let's say, have a bid price that is reasonably close to the clearing price, has a fixed relation. You look at the period of time after that and it starts to drift up. So you look at that and you say, well, the clearing price itself is going to reflect, obviously, normal fuel increases and other economic solutions. The fact that this price is drifting up in relation to the clearing price suggest, again, that's a behavioral issue. Something we've investigation. The congestion this year -- the total congestion cost at NEMA have been in the range of about $50 million. So, again, this is an issue that bears investigation.

So what do make from all this? I guess the take-aways are first. It is very important as the market is structured to pay close attention to market power issues and behavioral issues. Secondly, it is very hard to analyze them, and part of the reason that it's hard to do so is because the data that users have, that market participants have is restricted.

As Michael mentioned earlier, bid data is not available until six months later. So we constantly find ourselves in the situation of trying to understand what's going on in the market and essentially flying blind. We just don't know what the data is in order to do the analysis. There is a balancing between the needs of the generators and the others in determining what the appropriate period should be. But there's nothing magic about six months. Certainly, from our perspective, it should be released on a much shorter basis. We'd say at a minimum a month's delay would be sufficient. If you do that I think you increase the ability of all who participate in the market, which, in turn, increases the credibility of the market and the ability to find solutions.

Thank you very much.

MR. KRAPELS: I have found it to be productive to follow the instructions of FERC commissioners, so I'm only going to talk about transmission.

COMMISSIONER BROWNELL: Wish everybody did that.

MR. KRAPELS: I'm here as an owner of independent transmission. You'll note I'm not using the word "merchant" transmission. I'm using the word "independent" transmission. And, as such, was involved in the development of the Neptune project -- other projects that we are pursuing in the northeast and in other parts of the country. One thing we've learned in the development of transmission projects is that it is a very collaborative process and you have absolutely got to involve utilities, generators, regulators, investors and certainly consumer groups.

This is a wonderful place to talk about transmission and the role that it plays in economic dispatch. Obviously, dispatch is more economic if there is adequate transmission. Without adequate transmission, the problems of economic dispatch just get worse and worse. So I want to confine my comments really to four points about transmission.

My first point is that the drivers of future transmission development are changing somewhat. The typical tradition driver is reliability. But the change here in the Northeast especially is that the -- which are really marvelous vehicles in New England and PJM and becoming one in New York, are appointing on a region-wide basis where reliability investments need to be made and I think we're all learning from the NSTAR project and the NU projects that large transmission projects aimed at reliability inevitably have extremely significant economic impacts and that the distinction between economic projects and reliability projects is a little bit artificial.

The second change in the transmission development paradigm that we're seeing is what I call bringing power to -- We've got a long way from the Pearl Street Station development by the original Con-Ed to take power out of the city. Now more and more transmission projects are required to bring power into the cities and the urban areas. When you look at the really big transmission projects here in the Northeast, a new project, the NSTAR, the Neptune, the Cross Sound Cable, they're all aimed at bringing power into the urban areas. Why? Very obviously. Because building a 15000 megawatt power plant in the City of Boston at $2000 a kilowatt is a damn expensive proposition and may never be done. So transmission makes a lot of sense for urban power areas.

The third area of transmission development that we're seeing is, whether we like it or not, the body politic does consciously value generation diversity. We see that in a bunch of different ways. We see it in the emphasis on renewable resource requirements. To bring renewable resources into the grid, we have to build transmission. I can't tell you the number of wind-power transmission projects that we're looking at all over the country as essential to make this public policy goal a reality.

Similarly, if eastern PJM, if I may pick on a market that's not represented here, wants to have something other than gas in its generation portfolio. A project like Mountaineer makes an awful lot of sense. How's that going to get built? It would have to find a way to make generation diversity something that we're willing to pay for. We don't have answers to those questions, but the questions are arising nevertheless.

The second point I want to make is that we think that which may not be named, that is the capacity market constructs that we're working on -- LICAP, RPM and the capacity market -- the capacity demand group in New York combined with some essential long-term contracting were ultimately used as mechanisms to accomplish these transmission objectives.

In bringing power to the cities we're seeing a variety of approaches by New York public authorities to make it happen. Those initial long-term contracting requirements may erode as the market learns to put more faith in the capacity demand for an RMP. We'll not there now, but hopefully will be there in the future.

The third point I want to make is that, when you look at the Northeast from a transmission development standpoint, we clearly have two different regions. We have New England, which has an active RTAP, several major mostly rate-based projects and socialized projects underway. This way of developing transmission works in New England. And, if it works in New England, FERC has essentially said let it work.

These transmission projects have a tremendous impact on capacity values in the region. And so, without a LICAP or something like it, I don't know how generator investors are going to be able to make the economic analysis and look for capacity revenues to make their investments, hence, the need for LICAP here. In New York there's not so much an RTAP as there is active contracting for transmission by load-serving entities and load pockets. Even there, however, transmission projects do effect generator values and hence the need for a demand curve in the New York market. To me, it's an inevitability. It has to be a part of the standard market design whether you call it LICAP or demand curve or an RPM, which leads to my last comment -- the role of long-term contracts.

Participating in these discussions, it seems to me that we tend to think of this in too binary a way. I'd like to think that there's kind of a pendulum of contractual necessity. Five years ago you didn't need long-term contracts. Financial markets had a lot of confidence, some of it misplaced, and a ton of money was available to build generation. That model was more or less shattered by the collapse of Enron and by the realization that capacity revenues behaved the way that they did. So today maybe the peak need for long-term contracts to get anything built. Nothing will be built in New England without a contract from someone -- no generator and no transmission lines. But I don't want to stop there and say that that is the reality for the next 20 years. It's not.

Life works in pendulum shifts with LICAP, RPM and capacity demand curves and the erosion of generation surpluses. In five years I think we will be back again at a pendulum point that says we have a diminished need for long-term contracts. I don't think that need is going to go away in five years, but I think the need will diminish.

I'm involved in a transaction now with investors where we're actually looking at, and placing value on, the New York PJM capacity market spread. The investors are willing to put some reliance on the existing New York capacity mechanism and what they and we believe will be the PJM capacity mechanism as it emerges from FERC deliberations.

My last point is one I made earlier today. Restructuring is the work of a generation. It's not the work of two- or three- or four-year transition. It takes 20 years to restructure an industry as big as this one. That is our experience in the airline industry, in the telecommunication industry, so we're not even halfway there.

Thank you very much.

COMMISSIONER BROWNELL: It seems like a lifetime to me.

(Laughter.)

MR. LOUGHNEY: Thank you. My name is Bob Loughney. I'd like to thank everybody, especially Chair Brownell and the vice chairs for having been here. I'm a partner in a law firm in Albany, New York -- Couch White. We use a little bit of electricity, but that's not where I get my opinions from.

We represent, among a number of other clients -- my primary client is a group called Multiple Intervenors. The name doesn't give much away, but it's a group of large industrial, commercial and institutional users of electricity in New York State. Through five of the members, the Multiple Intervenors, actively participate in the ISO governance process, including the management and operating committee.

Again, I'd like to thank Chair Brownell and the Vice Chairs Flynn and Afonso for inviting me here today. We're particularly happy that the end use sector was included. It's a sector that isn't always heard from that I hope to bring a perspective here that may be a little bit different than what we've heard so far.

I believe I was invited here to provide the end user perspective by Chairman Flynn and that's what I intend to do.

With respect to SCED, it's certainly true most of the things that have been said -- the good things that have been said about the process. That it has been used in New York State in one form or another successfully for decades. It is a critical component, I believe, of the restructured markets in New England and New York. Customers, such as our members, Multiple Intervenors, require a reliable supply of electricity and SCED has been demonstrated to be a very good means of satisfying the reliability needs of New York State.

Certainly, using the least expensive resources to satisfy the electricity demands, while taking into account the transmission constraints and reserve requirements, although it's a very deceptively simple goal, it actually yields a very complex set of operational decisions that have to be made. I compliment here the way the New York ISO and before the New York Power Pool have done just a great job of keeping the lights on in New York State.

Despite the success and the fact that it's been a great way to ensure reliability, I do applaud the joint board's review of SCED and the examination of potential means of improving it. I have attached to my comments, which are available on the table, the most recent update of the LBMP prices in New York based on monthly averages 2003 to 2005. There's just been a dramatic increase in the price of electricity this year. I've heard all the explanations. I've heard all of the claims of savings. It's just hard to reconcile. I get beat up by my clients all the time in trying to give them the economic explanation for all this and they say, well, these prices are just outrageous and we can't afford it.

So I think that's the fundamental problem that I have with SCED. Right now it's subject to a pricing mechanism that is hard to explain and may not be yielding the most competitive prices available. If I could cite to one particular issue that seems to come up and that is we seem to have lost the benefit of the fuel diversity in the pricing mechanism.

In New York the market clears -- this is what I'm told by the New York ISO -- the market clears about 80 percent of the time based on the price of natural gas, which represents about 20 to 30 percent of the New York State generating capacity. Obviously, not everyone's costs are up when the clearing price is that high. There are a substantial number of generators in this state that are being paid on a regular basis a multiplier of their marginal costs.

I guess the question I have is, is this how it was suppose to work? It was designed a certain way. We've heard that there was a study in 2000 that said pay-as-you bid is the way to go. But I wonder if we revisit that study or update it to show real bidding information, real generation mix would it yield the same results now? Is this the most economic result? It's a question I hope the joint board's deliberations will continue to examine this issue carefully.

I guess the other issue that I wanted to point out, and I don't want to repeat what's been said, this is an area that really has not been talked about very much and that is whether demand resources are treated fairly under SCED?

Currently, in New York demand resources can participate in the New York ISOs energy and capacity markets. I think what makes New York a little unique is that the demand resources can actually have an impact on the clearing prices in the capacity and energy markets. I have been very involved with the demand resource markets in New York and I think the ISO had done a great job on the energy and capacity markets.

Right now demand resources are not able to participate in the ancillary services markets and some of those barriers are just software related -- things that are being worked on, not as fast as I would like to see them worked on, but being worked on. For example, some demand resources -- some of my clients are ready, willing and able to supply 30-minute, non-sink reserves but are not able to do so because the software changes haven't been made. There are other barriers that are more systemic and those barriers relate to the fact that there are existing reliability rules. For example, for spending reserves and for regulations that were written in a different era and really do not incorporate or anticipate demand resources.

I think that if SCED is going to be true to its purpose of dispatching the least expensive resources to meet the demand, demand resources must have an equivalent opportunity to participate in all the markets. Accordingly, I would urge this joint board to recommend to the FERC that it require that existing barriers, either software or market-related barriers to demand resources participating in all of the markets should be eliminated expeditiously. And that where necessary existing reliability rules should be modified to allow demand resource participation. Other than that, my remarks pose answers to the questions that were raise. I think some of it is repetitive of what's already been said.

The only other issue I would comment on is the consolidation of economic dispatch by integrating the New England and New York dispatch systems into one. I don't believe that consumers are opposed to such further consideration of this concept. However, given where prices are, I would want to be sure that before we do it that it's going to actually result in lower prices for consumers in the two regions. And I also think, having read some of the studies that were done in 2003, that it looks like it's going to be a very complicated process. And, given that, I would not want to interfere with other initiatives such as ensuring that the demand resources are incorporated in all these markets.

Thank you. If you have any questions, I'll be glad to answer.

MR. RUDEBUSCH: Good afternoon. My name is Tom Rudebusch of the law firm of Duncan, Weinberg, Genzer & Penbroke in Washington, D.C. My firm has represented municipal and cooperative utilities in New York and across the country for 30 years. I've personally been involved in restructuring New York since the competitive opportunities docket was opened in 1994 by the Public Service Commission.

I thank all the members of the joint board for the opportunity to present these comments, particularly our chair, Commissioner Brownell, Chairman Flynn and Chairman Afonso.

The New York Association of Public Power has nine municipal electric members and three rural electric cooperative members located across New York State. NYAPP members are load-serving entities with total peak load of 450 megawatts. NYAPP members have the goal of serving their communities reliably and economically. They rely on long-term bilateral contracts to meet their power supply requirements. They have access by contract to inexpensive hydro power under preference power arrangements that are commonly found in the western United States. In other words, there a specific federal statute, the Niagara B Development Act directing that power be sold at the lowest rates reasonably possible to NYAPP members and other public bodies. NYAPP members are unique in having these preference power arrangements in an organized power market and our clients around the country often ask of us how we're doing. NYAPP's members are also transmission-dependent utilities and dependent on the transmission facilities administered by the New York ISO to serve their loads.

As Mr. Lynch aptly demonstrated, they use the C-30 constraint economic dispatch as well as the security constraint. Unit commitment process organized around the locational marginal prices or LMP.

The New York ISO is arguably the most sophisticated example of standard market design in the country. The just released Department of Energy report to Congress is very able and well-written. However, in one respect I find that it fails to adequately address the distinction between bid-based economic dispatch and a cost-based economic dispatch.

Prior to the establishment of the New York ISO in 1999, the New York power pool operated a cost-based economic dispatch as well as a SCUC at a 10th of the administrative cost. Of course, the power pool did not also administer a bid-based market using LMP. The point is that no one should think that economic dispatch requires standard market design or locational marginal pricing.

The New York ISO bid-based economic dispatch produces a single market clearing price, both in day-ahead and real time. Recently, as was just mentioned, average monthly prices -- these are non-peaks -- but average monthly prices, 24/7, have increased in an alarming rate per megawatt hour. They were $80 in June, $90 in July, $110 in

August, $120 in September and back to $110 or something in that range in October. The cause is said to be high gas and oil prices used in the generators that set the LMP, but nuclear, hydro and coal generators are paid that same price even though their fuel costs have not risen to the same extent. This is a central feature of current bid-based economic dispatch. It's an issue that should be addressed by the joint board.

As I mentioned, NYAPP members have these cost-based contracts with very low rates. It follows that their retail rates are also very low. My claim is not that if you municipalize you can have cheap power with depreciated plants and free fuel, but there is another way to do it -- it was the intention of the yard stick competition envisioned by the Niagara Redevelopment Act that these cost-based rates would set a standard. We're not here to tell anyone what to do. But we're here to show that there is a different way to do it. However, the cost-based contracts do not meet the full requirements of NYAPP's members and they are forced into the market for the balance of their power supply. Here they have found that generators and other suppliers are not willing to enter into contracts that reflect their costs. Instead, some want prices that reflect the short-term market price.

While it has been said that a bid-based economic dispatch produces production cost savings, it is not obvious that those savings are reflected in the prices charged to load-serving entities in the wholesale markets or to retail customers. As a result, NYAPP members are investing in generation projects, including clean coal and small hydro facilities. This is the only way -- and this is the central point that I want to make -- this is the only way NYAPP members can capture the benefits of cost-based generation since a bid-based economic dispatch fails to produce the lowest cost outcome.

Just a couple points followed by the questions. One of the by-products of economic dispatch is uplift in all of its forms. These are significant costs often necessary for reliability, but the level of these cost must be managed through the ISO's governance process. For this reason, NYAPP's support of the New York ISO in its development of the expensive and evermore sophisticated real time commitment dispatch this past year. This required agreement on the five-year financing with a five-year budget target. The promise is that it will reduce uplift. It's too early to tell if this will work, but we are waiting.

Finally, NYAPP supports seams reductions, but does not believe that further consolidation of the New England and New York economic dispatch is needed if the goal is reliable service at the lowest cost. And, in terms of reducing seams between New York and PJM, I would just say one word and that is no SCUC.

Thank you.

COMMISSIONER BROWNELL: Don.

MR. SIPE: Thank you. I appreciate the opportunity to be here. I'm going to try to be brief because I know that you want to get into the discussion period.

I want to cover just a few points that are not necessarily all related to one another. I want to start with sort of a technical point that I think is unique to New England and New York, but I think has a bearing on the effects of economic dispatch on our markets and other people haven't touched upon it. It's something that's dear to my heart, so I thought I would touched upon it because we have talked about transmission expansion and its relation to capacity markets and other things.

I think New England and New York are blessed with a correct interconnection policy, which has large economic implications as far as how far down into the product mix we can push the results of security concern economic dispatch. We essentially have interconnection policy, which some people call "plug and play," which is known as the minimum connection policy. I'm to sure if all the commissioners around the table are aware of that policy and how it is different from policies in other parts of the country. We essentially have an ability to bring in new resources into the security constraint dispatch without building significant transmission as long as reliability is reserved. That is a significant difference, even from the FERC standard interconnection policy, which has in it embedded an idea called deliverability, which offline we can talk a little bit more about. But the deliverability idea, to me, is something like George Orwell's pigs who all together in the barn and decided that some animals were more equal than others.

Under deliverability there is this engineering illusion that some generators are more deliverable than others. The problem is pigs are serious.

COMMISSIONER BROWNELL: Hey, Don. Thanks a bundle.

(Laughter.)

MR. SIPE: I don't think that your personal policy. I think you listen to good sense when we propose something else. The problem is no one has proposed something else. These debates continue to come around, but we'll hear more about deliverability in New England. It's something, I think, as we look at the value of security constrained economic dispatch that we have to weary of. We have to be sure that competition in New England is, in fact, based on dispatching the least cost generation, doesn't have anything to do with preferential treatment on the transmission system.

I think we also continually come up against market suggestions in New England in some of our litigated questions that request that various carve outs from the transmission system be given to this party or another or FTRs. I think we have to review those quite carefully in terms of what effects they may or may not have on the general deficiency of dispatch in the region as a whole to the extent that they are simply financial arrangements that don't embody any preference or don't change any of the dispatch. That is one set of issues. I think we need to be careful to make sure that in the future that those are evaluated in terms of the economic dispatch implications.

I represent a group of consumers in Maine who actually saw quite substantial benefits from the implementation of the SMD markets. We actually saw a substantial reduction in prices. We happen to have a surplus in Maine. So I believe there is something to be said for LMP pricing and the economic efficiencies it can drive. It may be that those economic efficiencies were somewhat one-sided because we did have a surplus we saw that LMP prices could really drive people to bid very close to their marginal cost.

Let me say, as a transition, that that is not a normative outcome. That is a predicted outcome. Economics is not a normative science. There is no rule that people have to bid their marginal costs. There is only prediction that with enough competition they will be forced closer and closer to that number. I think part of the transparency in the LMP market -- part of the thing that it has shown us because it is transparent is that in order for those conditions to prevail, for there to be enough competition to push people to bid close to their marginal cost that this market requires a great deal more atomization than other markets that we're familiar with.

I think that was alluded to by some of the other speakers. Because of the nature of the market and the commodity that's being traded there is no such thing in the paper industry, for example, as security constrained economic dispatch. There is certainly economic dispatch -- economic dispatch based on whether I bid lower than someone else, but the security constraint piece points to something in the electric market. That I agree with Mr. Corneli, in fact, that it makes it very difficult to distinguish the exercise of market power from legitimate scarcity pricing. I'm not sure that I know the difference between those two things. I don't think there is a clear difference between those two things.

Security constraints dispatch is a tool -- I agree with some of the things you said earlier, Gordon. There's a tool aspect. It's a very useful tool and LMP is a very useful tool in many ways, but there's a fundamental disconnect between some of the ways that the security constraint mind set has to work. That certain units are absolutely essential and the way we allow people to price in the market. We've got to find a better way of pricing that difference.

It makes no sense for consumers to complain that people are bidding above their marginal costs. To me, if this was the paper industry, everybody would be bidding above their marginal costs if they could. So there's a disconnect. But I think it's also legitimate to say that if you're dealing with something that you can't do without that a pricing regime that allows something essentially to price as high as it can go is not making social sense. There is a normative aspect to what we're doing.

I think as we think through the process that security constrained economic dispatch presents us with we've got to be careful about assuming that a lot of demand response is going to resolve the fundamental underlying problem. The way I see demand response is that we ought to be encouraging that because it's efficient. But it is essentially another way of providing the service that generators are providing. To the extent we are doing things like peak shaving, well, peak shaving sort of destroys what it eats. The more you level off those peaks and get rid of that volatility through peak shaving the less there is to fuel the investment.

If you go to just basic conservation -- well, we can do better and conservation is a good thing. We ought to be driven toward it. It also eventually runs into entropy. To have a functioning economy, you can't just save your way or interrupt your way to production. You've got to get electrons across the wire. And at a certain point if everybody that needs reliability leaves the grid in order to get it, then I think the grid has failed. So the alternatives that you may be driven to, if you're thinking of only demand response as solution of the problem of scarcity pricing and what I consider is going to get down to be a necessity, I think some of the alternatives would be that we just don't use that system to the maximum that it could be used to.

The idea of having those alternatives available is a good thing. But I think essentially we get down to a lower demand curve somewhere. And, if we are still in the world where there is security constraints even there, and I presume we will be, whatever shape that demand curve has it is going to have security constraints that bind at times and that make some units necessary. If we are still in a purely commodity pricing market at that time, we have just moved the issue down a step but we haven't solved the fundamental economic problem or normative problem. I guess it's not an economic problem that an inelastic product wherever you get to it makes it very difficult to distinguish between the exercise of market power and what would be legitimate scarcity pricing if you were dealing with something that wasn't a necessity.

I want to leave the group with that set of ideas as one of the basic conundrums that I see in the market. I don't think it dictates a particular result. But, looking at results, I think we can't be naive in assuming that demand response is going to fix this whole problem. That simply letting the price go to infinity in certain hours is going to solve the problem. I think there is a larger societal decision that we've got to make that needs some more thorough discussion. That's all.

COMMISSIONER BROWNELL: Thank you.

I'm going to give Gordon and Mark 10 minutes or so to respond, then commissioners will open it up and to any others who would like to comment.

MR. van WELIE: Actually, I hopefully should be done in shorter than 10 minutes. I wanted to come back to this pay-as-bid versus the marginal cost current system of clearing based on the bid-based clearing mechanism.

The thought that occurred to me, and I shared this with Kurt over lunch, is the problem isn't with the market design. The problem is with our citing policies. What we're anxious about is the high cost of electricity because natural gas has increased in price in terms of fuel that's been reflected in terms of electricity cost. And what the market is telling us is do something about the price of natural gas and do something about your generation mix. But we have so overly constrained our ability to cite something other than natural gas, particularly up here in the Northeast and we have so constrained our ability to import additional gas molecules into the Northeast that we've put ourselves in the corner.

I'd say let's not go and undo all the good with respect to the market design. Let's apply the energy that you have onto the problem of citing alternative supply resources and making sure that you've got enough fuel to actually convert it to electricity at a low cost. That was kind of the first point I wanted to make on that. To gulp down this other part of having to undo what we've done would be enormously unproductive.

The other point I just wanted to make is we need to be careful not to get wrapped up in this notion that we have to eliminate congestion. Making congestion go down to zero is not necessarily the right economic outcome because there's a cost associated with achieving that result. So I think what we're in, in New England, with respect to transmission investment is the first wave of investment, which is all reliability-based. Once that's behind us, I think what we'll now be exposed to is the next round of transmission investment, which is going to be looking at is it economic to make this investment in transmission because we don't really have a reliability justification for it. That, I think, is going to be far more difficult. I think if you leave it alone enough like we did in Connecticut, eventually you have a situation like you've got a bad reliability problem on your hands and you've got no where else to go.

Those are really my only two thoughts that I wanted to respond on.

COMMISSIONER BROWNELL: Thank you.

Mark.

MR. LYNCH: Looking in my crystal ball, I have to agree that we are at sort of the high point of the pendulum. I do think we ought to start seeing some movement. It may not be as quick as some people would like, but the need for long-term contracts, and I like the term "long-term," because in my past life when I was a developer long-term was 15, 20 years. Long-term today is five years, maybe longer.

I know in the case of the transmission projects, it is 20 years. But a lot of the power purchase agreements that are in place, at least in the New York control area, are more like five years for capacity only. So you don't cover your cost and they do it very short-term, which is not even the average term in the debt that's out there. It's sort of an incentive to get there. I do think we will see a shift that will be slow, but I think he makes a very good point.

The other point I want to just caution everybody, and I've heard it before, prices are high right now. When you look at the price of gas and you've seen that it's doubled, gone up 70 percent or more from last summer, I think you would realize the prices would go higher. When you look at a system that previously we had a peak of around 30,000 megawatts, and it went up to 32,000 this summer, it's a huge increase. We've seen a dramatic new peak set here and that strains your resources and you go to a lot higher cost resources. But I do want to caution people because I don't think you can expect that fuel price is going to be the only sustainable thing here.

A lot of my market participants have data that I provide every month that shows the increase of fuel, increase in locational pricing. If you look at fuel increase, it has been in that 12 to 20 percent range month on month as we went through the summer where locational pricing was increasing somewhere between 8 to 10 percent. Big difference. You sit back and say, gee, it's not all fuel. There's something going on here.

I do think we have to look at the anomaly -- what's happening with gas. Some of it is the commodity. Some of it is the result of what happened this past summer with Katrina and Rita coming in. There is a strain on our infrastructure system and I don't think we so excited at what we're looking at here. I think you could do that very quickly looking at where we are with gas prices.

The last thing I'll say is that Gordon brings up a good point. When you look at locational pricing -- it was said, I think, by somebody earlier that they're not sending the right signals. I think they're sending all of the right signals. They're telling you all of the right things. Arguably, they may not be robust enough to get investment on their own, but I think there's a lot of other entries into the capability of actually sighting generation or transmission in specific areas that have to do from environment to political to just other types of social reasons that are out there that I think people negate. They think that locational pricing is the end all or the solution to the end all problem that you have there.

They are sending the right signals. They're sending the right information. I think there's other underlying things that are going to have to be resolved in conjunction with maybe making those signals a little more robust to basically incite investment.

COMMISSIONER BROWNELL: Thank you.

Commissioners, questions?

MR. REESE: John Reese with New York.

I just want to clarify, for the record, Tom, in your presentation you spoke about cost-based bilateral contracts at $20. And, Bob, sitting next to you would kill for those.

(Laughter.)

MR. REESE: It should be clear that those are based, I believe -- correct me if I'm wrong -- those are based on state subsidized hydro projects that you had a nearly unique relationship with in those contracts. And that, in fact, with or without a market or economic dispatch that $20 number would not be generally available.

MR. RUDEBUSCH: First of all, they're not subsidized in any way. They're depreciated plants. They're cheap hydro fuel. We pay cost-based rates. In fact, we think we pay a little too much.

I also note that I believe the bus bar price at Miami Point is not too much out of that range. There are a lot of producers out there that are producing energy at cheap prices and getting high prices based on the price of natural gas right now. So that we understand the distinction between the bid-as-you pay approach versus the single price auction that was debated back when we designed the markets in the mid-'90s.

The problem with pay-as-bid is said to be it leads to collusion among bidders and requires more market monitoring. Nonetheless, be that as it may, it does not have the effect that the single price auction has been having on prices and on revenues this summer.

MR. LOUGHNEY: I just wanted to reply to Gordon's point. The whole idea of sighting and what the price signals are, I think Gordon and Mark are correct. I think the price signals are out there for sighting different types of plants where they're needed.

As everybody here knows, there's a whole lot of politics that goes on with all of this. I don't know if there's enough energy in this room in order to get the sighting rules changed to where they need to be. Certainly, we're supportive of that. I don't know that that would change everything, though. We have pretty good fuel diversity in New York State.

Certainly, if we don't build new types of different plants, we're going to have a bigger problem than we have now. Even with the diversity we have now, the market is clearing 85 percent of the time based on gas.

MR. LYNCH: I'm going to check that number on you. I'm not there with you on that. I was going to be kind and not challenge you here, but I'm going to check that number. It could be gas and oil. I would agree with that because we have a lot dual fuel plants and then we say gas and oil about 60 percent or 50 percent -- yeah, 60 percent, I think, are oil/gas in the oil and gas mix. Probably what you're seeing is the large boiler-type oil units sitting on the margin there. Those are pretty inefficient high-cost units, especially where the cost of oil has gone over the last three or four months. I think you're seeing some of that impact. I may go there with you.

MR. LOUGHNEY: I stand corrected then. But I mean the point is that the other more diversified types of plants are still clearing at that price. I'm not sure that if we put more coal plants I don't know that it's going to effect the way the clear price is happening anyway.

COMMISSIONER BROWNELL: Kevin.

MR. BURKE: A couple of things. When I finished my comments, you'd asked if I would comment on some seams issues, which ones are not being worked on. I think somebody made a comment earlier that the software is complex. The system is very complex and the software that runs that is necessarily complex.

Every time I ask Mark to make a change in the software, I've made his software more complex. I mentioned before this minimum oil burn that adds complexity to his software. He needs to take the time to make sure that the software changes are correct and they've been thoroughly tested. So I think, generally, it seems like it is a process. And it is a process, but it takes time to make those kind of software changes, so that's not a concern that we have. We're working on these issues and I think we're moving forward.

I'll just mention a couple of other things. When I go around the country, people frequently say, well, you could never build a generator in New York City. The last two summers we've had two generators come online and by next summer we should have a thousand megawatts, two 500-megawatt units owned by two different owners now in the final stages of construction in New York City. It's important that people take a look at how we solve the customer's problems. The customer is looking for energy. Gas is on the margin and gas will be used in New York City. We haven't burned coal in New York City for three decades at least.

When that happens, when a gas line is brought into New York City it's important that fuel gets used in the wintertime for heating. And then, if it's used in the summertime in the power plants. It's more efficient than building the power plant a hundred or 200 miles away from

New York City and then build an electric transmission line down in addition to a gas transmission line up to that power plant.

I think sometimes people look at will transmission reduce the cost from an economic dispatch point of view. It will. But what we're really looking at is the economics of the entire market delivering that electricity to the customer, whether that is through the utility or through one of the independent energy service companies. They all see that market price, but they also see the transmission lines that are built to serve those customers.

Another issue that sometimes comes up is, is there a difference between transmission built for reliability and for economics? I think there is. We have a processing place in New York that can identify transmission lines built for reliability. Those costs get socialized. If a plant is being built by an independent party for economic reasons in a market, it should be willing buyers and willing sellers looking to see who is going to use that transmission line, not necessarily socialize those costs over the entire service area or some other service area.

CHAIRMAN AFONSO: Thank you.

Obviously, Kevin just blew my line that I usually use, which is that you can't sight anything here in downtown Boston. He tells me he sights two things in New York City.

So thank you very much. I appreciate it.

(Laughter.)

COMMISSIONER BROWNELL: I was going to get you on that.

MR. HURON: Boston's not New York.

(Laughter.)

COMMISSIONER AFONSO: That's what I'm saying. Let's keep it that way.

(Laughter.)

COMMISSIONER AFONSO: A couple of points. There are many things in the last hour and a half or so, so I went through a few notes.

Bob, I think your point, as you're sitting there, and I think Don had the same experience with real customers running manufacturing plants, running businesses, their focus is running the business, not everything else, is their core mission. And when I see their rates go up and then you tell them, well, here's a study that demonstrates all these good benefits, apparently the same line we use here in Boston doesn't work in New York either, but it could have been worse is I guess the line. That doesn't fly either. So I agree with you.

One of the issues that's sort of been buzzing in and out on natural gas fuel diversity -- it's obviously not the subject right on in today's, but it's an ancillary, an important item about the clearing price issue. Obviously, you know, my colleague from Rhode Island, his governor has written in on this important subject. Without going into a long discussion, that's a separate full day of discussions, just procedurally my colleagues from the ISO and others -- I know that issue has been engaged in many formats. Can someone take inventory as to how many formats it's been engaged in and will be engaged in again in terms of some of these issues as to the pros and cons? I know there were some recent studies done on that. I don't remember them all, but is there a delineation in terms of responding to that or engaging in that important issue?

MR. van WELIE: No. That paper that I just gave Christine I think we should get a copy of that to you as well because they do a nice job of explaining why pay-as-bid won't work relative to our current system.

But, just to repeat what I said this morning, what we've got is a system with our current clearing mechanism which incents generators to bid their marginal costs and they know they can do that and be paid the differential between the clearing price and their marginal costs. So they don't have to sit there and guess what they think the clearing price of the marketplace should be. If you reverse that and go to pay-as-bid, the somewhat naive assumption that generators are still going to bid their marginal cost into pay-as-bid auction, of course, they wouldn't.

Don just made the point, if you're in the paper industry, you have to bid for full cost recovery. You've got to bid your marginal cost. You've got to get fixed cost recovery as well. So now you're a nuclear plant. Instead of building it at zero, well, okay, I'm going to replace this nuclear plant 20 years from now. What should my bid be? I've got to cover all the environmental rehabilitation. What should my bid be? You've basically got to factor into your bid your long-run cost recovery. That's the one thing you've got to do.

The other thing you've got to do is say, well, I've got a profit motive and I would like to see where I position myself in this market. I've now got to bid at the sweet spot just below what I think is going to be the most expensive unit bidding into the marketplace. When the economists have looked at this -- and I'm not an economist. I'm just giving you my layman's interpretation of this. When the economists have looked at this, they have done as much as theorized about this, but they've actually run simulations. They show that you get a higher price using that system than our current system.

Unless somebody comes to us and says here's evidence that you're going to get a better result using pay-as-bid, I don't see any reason why you would want to spend a lot of time looking at that. But I'm open to somebody showing us that we're wrong in this respect.

MR. LYNCH: Just from my perspective, I thought we had this debate and ended it that uniform pricing was the best way to go and that's essentially where we've gone. I guess we're rehashing old ground. Maybe memories are short.

COMMISSIONER BROWNELL: That's why it takes several generations.

(Laughter.)

COMMISSIONER GERMANI: I have a question if anybody wants to take it.

We've had indicated to us all these savings in the market. What would those savings had been if we had to pay for the generation that we didn't pay for which we'll be paying for under LICAP? We were asked not to talk about it, even though someone else did -- or a similar mechanism.

MR. CALVIOU: I was told to try to produce an answer to some of the issues, maybe to that question as well. I think there's probably three models being talked about. There's two competitive market models. One with marginal pricing, which we all know and understand. The one with pay-as-bid, which I think, as the report -- people are misquoting. If people ask them what the margin is, they're not always going to get it right and we do inefficiencies.

I think what I was hearing was, isn't there a different model where we just basically pay people their costs? That's a completely different model. That's not a market model, pay-as-bid. That's a cost-based model. It's a different model and I think we have to remember there are features of that model -- yes, you get the obvious headline saving on coal, nuclear and hydro that's not at the margin that gets paid lower, valuable costs, but also it has to get it's cost paid for as well.

Some of the sort of high prices that we're currently seeing, which you're going to basically aplant if they look to be short-term profits, but they're having to contribute to those plants fixed costs and those plants have capacity payments as well, which contribute to some of those fixed cost. Basically, an efficient market -- that's the way an efficient market will be developed. Those plants have actually fixed costs they'll have to recover on the sort of profits they make -- the difference between their costs and the marginal costs will go toward paying those fixed costs back.

I'm sure if you did a calculation over the past six months you'll find they got those costs back and more. If you go back several years, you'll find that they had some lean years. I think you need to take the long-term view and understand it's not quite as simple as just saying I would only be paying $30, therefore, I'm now paying $100. Therefore, I'm making $70.

There are different models, different paradigms there and I think that's sort of played into Chairman Germani's question. I think, yes, as new capacity is needed on the system that will increase the cost to consumers. I think some of the 40 billion type cost numbers, savings that have been quoted, are due to the fact that there's been excess capacity on the system and there has been maybe a short-term gain. I think probably long-term gains are going to be less, but I think it will sustain the benefit of innovation and things like that. I think you need to measure over a long time so you see the play of the various business cycles.

As I've got the mike I thought I'd want to respond to a couple of you on transmission issues. I haven't said much about transmission. I'm particularly responding to Kevin's point about reliability versus economics.

I think several people have said reliability and economics are very closely intertwined and what we do in certain regional planning processes isn't necessarily a sensible idea. The nice theoretical idea of leave economics to the market would be great if actually the modes of transmission and market transmission worked. But we only see a couple of MIPS opportunities for merchant transmission to work. Neptune and the Cross Sound Cable are good examples. All such projects are between market regions and very often they're backed with long-term contracts and some entity like a state agency that can take a long-term commodity list.

I think if we do want our cost transmission systems for economic dispatch then I think we do need to look at policies to promote transmission and I think at planning for economics and seeing whether there is regulated transmission make sense to build support -- renewables to support fuel diversity. Those I think are sound policies.

COMMISSIONER BROWNELL: Thank you.

I, myself, can no longer distinguish between economic transmission and reliability transmission, so thank you for bringing that up.

Harry.

MR. SINGH: Just a quick comment on this price auction debate. I'd add one more argument to the ones that Gordon mentioned.

A lot of the trading happens in the bilateral market. Now a lot of these trades are financial. The reason people can do financial swaps easily is they're indexed to one price published by the ISO. The buyer and the seller see the same price. The moment you go to a pay-as-bid you're paying different people different prices. You basically destroy that construct. So a lot of the financial swaps that we see out there, which are fairly liquid now in some locations, would become more difficult.

On the basic report that Gordon mentioned, I read that report. I also read more recent work since the British experience of going to pay-as-bid, which suggests that you can have lower prices under a pay-as-bid construct on some occasion. This is something that has to do with when the generators try to guess the market clearing price. If you consider operating constraints than base-load units that run all the time, they may not always guess the marginal price. They may say I want to bid a little bit lower just to guarantee I'm always running.

The net effect could be that you end being less on some occasions, but this comes at a price. It comes at the price of destroying efficient dispatch, if you will, going to this morning's discussion and if academics have done a game theoretical analysis the only construct that gives you an equilibrium bidding strategy of bidding at cost is the uniform price construct. So going away from that to save a little money is taking you away from efficient dispatch. I'm not sure that you want to do that.

COMMISSIONER BROWNELL: We'll get the report to which Gordon referred in the record. Be sure we get the most recent report in the record as well.

Gordon then Commissioner Adams.

MR. van WELIE: I just wanted to respond to Commissioner Germani. I should clarify that the numbers that I was referring to earlier today were energy market analyses. We didn't look at capacity market impacts. To do that you'd have to look at what was paid under the capacity market over the last four or five years. This is what should arguably been paid and then projecting that forward. There are two different things going on there.

I just wanted to clarify that. It was narrowly focused on the energy market.

COMMISSIONER BROWNELL: Kurt.

COMMISSIONER ADAMS: Thank you.

Honest to God, I came today promising I was only going to talk about security constrained economic dispatch.

(Laughter.)

COMMISSIONER ADAMS: But I digress just a tad.

COMMISSIONER BROWNELL: There's a price.

COMMISSIONER ADAMS: I just want to follow-up and really sharpen this issue, to tee this issue up on pay-as-bid versus marginal pricing or the Dutch auction is probably not exactly what loads concern really is. Loads concerns is if you can't sight new generation that is not gas-fired in New England. What you do is create a perpetual market dynamic in which those at the bottom of the bid stack receive what appear to be inequitable rents, so they're placed on the bid stack year in and year out. That will always exist if you can build nothing but gas, you'll perpetually going to keep gas on the margin.

To bring this down to a very human cost, there are a lot of jobs leaving the state -- in my state and the region. I think what is probably going to wind up bringing gas prices down -- and it makes me anxious to say this, but I think it's true -- is more demand destruction and fuel diversity. As these jobs leave the area, we'll have less demand. That's going to wind up driving public policy debate over time. The level of intensity around the debate, particularly from the load side is not insignificant. We don't see any way that we can change the existing dynamic in the medium term except by adding more gas-fire generation to meet capacity constraints.

Chairman Germani's question, which is a very wise question and I think I've gotten the answer out of Gordon once before, and I think you might have missed the question he was asking. What he was saying was we're going to pay for this new capacity. How much is going to cost? The ISO did a study that said we save $13 billion by moving to a restructured market since 2000. Isn't that what your study came up with? That restructured markets have saved consumers $13 billion over the first five years in operation.

(No response.)

COMMISSIONER ADAMS: What is the number.

MR. van WELIE: The only number that's out there at the moment is the set of numbers that I shared with you this morning. Bob pointed out to me within that $700 million there is a component which is the increased availability of generation. So what you're doing is avoiding having to purchase new generation by the amount that you've increased availability. That was priced at the going-forward cost of a peaker, but apart from that, we haven't done any analysis to say what capacity should have cost or tried to do any comparison over that five-year period versus looking forward. The $13 billion number that mentioned doesn't ring any bells.

COMMISSIONER ADAMS: It may have been extrapolated from the SERA report they put out.

Chairman Germani's question, to paraphrase it is, if we had LICAP, what would the cost of the market have been for the past five years? It's a fair question because it puts in perspective the full market dynamic.

MR. van WELIE: Arguably, we would have paid more I think is the answer.

COMMISSIONER AFONSO: A question off this topic, if I may.

Earlier there was a lot of discussion on software. I think that's where the word "algorithm" comes up. That usually loses me after that discussion. But the quality of software, can we just talk briefly on the significance of the software to date in terms of the state-of-the-art? What more is being done in terms of perfecting the software, if I have that correct? There was some discussion very early in the discussion.

It may have been you, Steve, or other colleagues who mentioned that's such an important part -- generally speaking, where that is in the art form now.

MR. van WELIE: I think there's two parts to answering that question. One is there are a number of improvements that are market-design related. So if you look at something like ancillary services Phase 2 that has an co-optimization of energy and reserves within it -- I use that as an example of a wholesale market improvement that also has a market effect into any improvement in the market dispatch software. Those are clearly identified and we have large projects underway to deal with those.

There's another set of improvements which I classified as research and development this morning. Things like improved combined cycle modeling, building to the software, multi-interval optimization and so forth. Those are the things which we're not ready yet to commit to as firm projects for varying reasons. The use of MIPS is one of these topics, multi-integer -- I forget what the "P" stands for now, but it's a different optimization methodology which some claim will actually produce better results. We're going through a process of evaluating that within the ISO to convince ourselves that that is, indeed, the case.

Once we get to that point that we feel that we'll get a better result from MIPS, we will then obviously have a case for switching to it. But it's really an issue of resource application is what it boils down to. So, if you look at what we have, we've constrained our budget to have a $20 million a year capital budget within which we have to find all of these initiatives. That then forces us to work together with our stakeholders to prioritized all of these activities.

So while those things need to be looked at they are not at the moment right at the top of the pile from a priority point of view.

MR. LYNCH: Maybe I can answer that in a little bit different way. It goes to the software itself and its complexity. We just issued a new platform and used a certain vendor, which we've worked very hard with, probably two years, prior to putting that out. We did a lot of testing, a lot of regression testing on it. We rolled it out in the beginning of February even though the testing did find numerous problems within the application of the software and how it ran, both in the day-ahead and real time market. We worked very hard with our market participants as well as the software vendor to fix this.

One of the things you heard Kevin mention before that we're actually initiating internally is that if we develop these new projects and look at different things if we want to add an application we realize that it is probably better to take our time in the sense of actually testing these out to go through a fairly robust and rigorous test environment to make sure that when we roll them out they actually operate as planned and basically put them in an environment where we can make sure they don't effect any other part of our market.

It was alluded to before that the software has become very complex. What we do is complex. As a result, I think you have to take the time, the effort and dedicate the resources to put in new products. One of the things we're looking at is the quality control types of things that we do internally to assure ourselves that if we put a product out for market participants that we can see a seamless transition. It's something we realize and we're working on and we have to address.

COMMISSIONER GERMANI: In my earlier life I was a software development counsel. Software always costs more than development might cost -- a hell of a lot more and will never perform. This is why your software development contracts, which are done by software development lawyers promise very little and have it wide open for extras. So just be aware.

(Laughter.)

COMMISSIONER BROWNELL: I'd just like to point out that we share the frustration of software costs. We've actually had to technical conferences on it. Three and a half years ago we hired Gestalt, a consultant, to do a study about what drives software costs. It's actually a pretty good study. It will teach us what you learned the hard way I gather. I learned that in the banking industry, too.

There were three critical themes. The cost drivers are delay, uncertain market design so when you start to build and you start to make a change over here without considering the totality of changes and a stakeholder process, that lead in some cases to a lot of proprietary software and what I would call "goldplating" fixes that probably didn't have the value that it should have.

Quality control is important, but frankly ever stakeholder should not get what they want. It should get costed out and the group who are going to write the check should say, yeah, we think this is important to us. So there are lessons learned and I think we should have enough experience under our belt that we've learned those lessons as well. So it takes time and effort, but it also takes a little more discipline than has been exercised in the past.

Gordon.

MR. van WELIE: I just wanted to add to what Mark said. The secret to having good quality software is twofold.

In the first instance when you're building something new, thorough testing and taking the time to do the testing thoroughly and not trying to run in 15 market changes in a 12-month cycle. That is a recipe for disaster. What you've seen us move to in New England is, at the moment, we're doing no more than two major releases is our plan in any particular year. I'd like it to get down to one major release per year. We always do these in the spring and the fall. That's because you then put the discipline into the organization to focus on doing a quality job.

The second part of introducing quality is to have a quality mentality within the organization. We've put a lot of effort into that in the last couple of years where we've put into place a quality management system centered around the ISO 2001, 2002 standard. That has helped us a lot in terms of finding problems because there's no such thing as an error-free piece of code. It just doesn't exist. You need to be there looking for the problems all the time. It's a never-ending job.

COMMISSIONER BROWNELL: Quickly. Then we're going to let Chairman Flynn make a few closing comments.

MR. SIPE: Chairman Germani, I just wanted to respond briefly.

When we saw saving we tried to do an analysis of where the savings were coming from. When we to LMP we found that, in fact, part of the savings that people really were, at least in surplus situations were really driven by the device to bid very close to their marginal costs. That also meant that there were a lot of people not covering the capacity cost out there in the market. So a lot of our savings, at least in the surplus situation that we experienced were from under-recovery of capacity costs that we would otherwise have been paying.

I think the question that you have to bear in mind is that may have been the initial savings, but is that a sustainable situation that will always be and are people going to continue to invest in and lose money? In the long term, the answer has got to be no. You either have something that stabilizes these prices over time in some way or you allow the market to really move in a boom/bust. But I think it's a legitimate question where we saw the savings coming from. That was initially we saw a lot of what some people call bad investment, but I just think it was investment that we didn't get charged with. So at least that part of that market, in the proper conditions, actually works. I think it goes back to the as-bid discussion that we had. I have actually done a survey of the literature on it trying to answer this question for a client. I'd be happy to hand you my two volumes of books if you want to take a look at them.

I have to agree with my chairman. I don't think it's the largest issue out there in front of us because the change an the bidding behavior there are some studies out there that say that it's cheaper to do it that way. But I think, given the other challenges on our plate, it would probably not be the best use of our time to go back and try to catch some smaller savings with the complications that I think we'd get in our settlement because of it.

COMMISSIONER BROWNELL: Bill.

CHAIRMAN FLYNN: I'm going to have to leave. I have to make it to a wake by the time we get to Albany. But this was a wonderful opportunity for us all to share ideas, but I'm a big believer in follow-up. This is great. All getting together today, but I hope we don't forget what we've learned today and I know that Nora and staff are going to lay out a process here going forward for more input from not only the people here in the room, but the other people who were unable to come today. I even think we're going to have an opportunity to get back together, hopefully, around February. Nora will lay that out for you.

So, on behalf of New York, we appreciated coming to Boston. You are no longer invited -- I just want to let you know that.

COMMISSIONER AFONSO: Let's hope the meeting in February is in Manhattan.

CHAIRMAN FLYNN: It can be.

Again, I want to thank you. We'll see you on down the road.

COMMISSIONER BROWNELL: Thank you.

I got in trouble at the last meeting in Chicago for not opening it up to the public for comments. So if the public is here and has any comments now is the time. Unfortunately, Chairman Flynn will have to read about them.

(Laughter.)

(No response.)

COMMISSIONER BROWNELL: I have fulfilled my mission, Sarah. I didn't close off dialogue.

Paul, do you have any comments.

COMMISSIONER AFONSO: Simply to thank everyone for outstanding presentations. The reality is we get into our day-to-day grid and it's good to pull back for day or so and think these things through. We had a lot of different so I'm very grateful.

Thank you for your leadership, friendship and hopefully we'll do this again shortly.

COMMISSIONER BROWNELL: Let me just review the process with everyone.

I, too, am grateful for your input. These are very complex issues and candidly we are not a country that likes to make long-term infrastructure investments in the way our great grandparents did. When you look at infrastructure studies, I think the most recent study I read was that we are about $1.6 trillion behind in investment in energy, in water and sewer infrastructure and in roads. So I think we have to keep in mind what we're doing here in a time of enormously high fuel prices and volatility in the marketplace. We're also trying to solve some problems we've ignored for too long. We have to keep those separate and distinct in our discussions.

We will have 21 days for comment. Please get your comments into the FERC. Recommendations -- any studies that have been referenced we will make sure in the record we'll make sure any comment that implicate in other dockets will be put in those records so that we are all on the straight and narrow. We will convene by conference all with the commissioners as we get the recommendations in and review with them. We will get those out for their comment and meet again in February at the NARUC meeting. Date to be determined.

Feel free, in the intervening moments, if there are ideas that didn't come out here that actually have to do with economic dispatch, please feel free to put those on the table as well. We all get home and have new and brighter ideas.

To the extent that anyone mentioned numbers that are challenged, and the two of you need to get together to make sure that the record actually reflects those numbers, please do so. The debate is best served by a rigorous examination based on the facts.

I appreciate your input and look forward to hearing from you. Thanks a lot.

(Applause.)

COMMISSIONER BROWNELL: We are adjourned.

(Whereupon, at 3:55 p.m., the above-entitled matter was concluded.)