1 BEFORE THE
2 FEDERAL ENERGY REGULATORY COMMISSION
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6 IN THE MATTER OF: : Docket Number:
7 ISO NEW ENGLAND INC. : ER02-2330-029
8 : ER04-1255-000
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12 Seaport World Trade Center
13 Harborview Ballroom
14 200 Seaport Boulevard
15 Boston, Massachusetts 02210
16
17 Friday, March 4, 2005
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20 The above-entitled matter came on for technical
21 conference, pursuant to notice, at 10:10 a.m., Chairman Pat
22 Wood, III, presiding.
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1 M O R N I N G S E S S I O N

2 CHAIRMAN WOOD: Good morning. I'm Pat Wood,
3 Chairman of the Federal Regulatory Commission. I am joined
4 here by my dear friend and colleague, Nora Brownell. The
5 two commissioners are on the other coast, but we split our
6 duties now that we're up to four.
7 But I got the better duty to come to a hometown
8 where the headlines -- we always investigate utility
9 headlines where we go so we have good local intelligence.
10 And our headline today said the Attorney General
11 who generally tend to be active in every state where we go
12 is blaming the regulatory commission for a dog's death for
13 relieving himself on a light pole. So I'm glad to be from
14 Texas, folks.
15 COMMISSIONER BROWNELL: I owe him 50 bucks for
16 reading that.
17 CHAIRMAN WOOD: She dared me to do that. We are
18 here to discuss where we all are going and I call this the
19 best fuel market in North America and it's been a real
20 pleasure as a member of FERC the last four years to watch
21 the developments of this market from where you started in
22 the late 90's and progressing through a lot of changes,
23 developments, improvements and refinements, but I know there
24 is still work left to do. And that's really the focus today
25 of our conference.

1 We were invited to come up here by the ISO and by
2 the NEPOOL to come up and visit with you all and Nora and I
3 had a nice visit yesterday with the leadership of the pool
4 and talked through some procedural issues. Nora is going to
5 visit about one of the items that fell out of that
6 particular discussion yesterday.
7 Today's conference is to focus on the
8 implementation of some important issues that the ISO and
9 stakeholders have been working on up here. We wanted to
10 come up here and not only lend our ear to that effort, but
11 also to ask questions about where we are going and what the
12 next steps are and what our Commission can do to help. What
13 our colleagues at the state Commission can do to support the
14 process or contribute anything that they need to do.
15 So with this, what I think is a very successful
16 enterprise over the past several years can continue to be a
17 collaborative and forward looking and customer serving
18 enterprise and that's what we should all agree upon that we
19 are all about.
20 So I want to turn it over to Nora for any
21 thoughts she's got.
22 COMMISSIONER BROWNELL: Thank you, and I'll be
23 writing a check promptly. We had, as Pat indicated, a
24 wonderful meeting as we also do when we come to New England
25 and actually I think this team wins the award for best venue

1 and I'm also told for best menu to be in a room that has
2 light and water and beauty after we visited, I think the
3 ugliest conference rooms all across America, so we'll be
4 back.
5 (Laughter.)
6 COMMISSIONER BROWNELL: You get your priorities
7 straight after a while. One of the discussions that we had
8 yesterday was how to effect better communication with the
9 participants committee and we concluded, after some really
10 good input from the entire team, and thanks to Don Sipe, who
11 I gather carries a big weapon for those of you who are
12 experienced. We thank him and we than you that we would, at
13 the very least begin to schedule monthly conference calls,
14 but we would also have the team actively involved in the
15 participant's committee.
16 Not with the idea that we would necessarily be
17 intervening in any meaningful way, but simply so we can have
18 a better flow of information back and forth, anticipate what
19 might be coming, share ideas in other markets.
20 As many of you know, we have actually divided our
21 agency into teams so that we have expertise depending on the
22 region. Anna Cochrane who is here, Anna, if you could wave
23 your hand, is the head of the team for New England and
24 really wonderful team leader whose expertise we value.
25 Working with her is David Kathan, an Economist

1 with OMTR East. David Mead, an Economist, and supporting
2 them is Kathy Waldbauer from the Office of General Counsel,
3 along with Jeff Dennis in the Office of General Counsel,
4 Julia Tuzun, an Economist in Market Oversight, who has been
5 attending market participant meetings, and Hari Singh, who
6 is also an Economist.
7 So you have the best and the brightest, frankly
8 at FERC supporting your efforts. We hope to be working
9 together much more closely.
10 And as we said yesterday, it's a quick flight
11 here so anyone of the Commissioners can be here, although
12 the really smart people are the people on the team, but I
13 live in Boston so I would love to be here.
14 I'm excited about that and I know the team is.
15 We have already had a quick meeting this morning so this is
16 the best market although I won't tell you what Pat says when
17 he is in Texas
18 (Laughter.)
19 COMMISSIONER BROWNELL: But it is the best market
20 and you're ally leading the way and we are grateful for the
21 efforts. We know you all have day jobs but you have been
22 really committed to make this the place and we are very
23 proud of you.
24 CHAIRMAN WOOD: In kicking off, I did want to say
25 as far as the best market. One of the things about the

1 stakeholder process here is the NEPOOL relationship, which
2 existed actually long before there was an ISO. It was one
3 when I was a retail regulator in Texas we looked at as the
4 example, and yesterday's meeting reconfirmed why that was
5 the example to borrow from as far as the stakeholder
6 process. It's very inclusive and very focused on outcome
7 and results.
8 So we are proud to be back and I want to turn it
9 over to Gordon and Donald for their remarks. Gordon, you're
10 first up.
11 MR. VAN WELIE: Thank you very much. Good
12 morning everyone. The first thing I'd like to do is to
13 thank the Commission, Chairman Wood and Commissioner
14 Brownell and the FERC staff for taking their valuable time
15 to roll up their sleeves and get involved in some of the
16 details up here in New England. It's very important.
17 I am certainly encouraged to hear about the
18 commitment to have further involvement at the PC and look
19 for ward that we try and make sure that the various
20 It's very important that we do try to make sure
21 that the various parties here converge as we plan the
22 evolution of these markets and I'll be speaking to some of
23 that committee. Can we have the next slide please?
24 (Slide.)
25 I thought what I'd do is start the discussion

1 with what we as ISO New England hope to get out of this
2 conference. I'm sure there are perhaps similar objectives
3 in some way and there might be different objections. But
4 from an ISO point of view, this is a very valuable
5 opportunity for us to address some of the points that are up
6 there on that slide. I'll just run through them briefly.
7 The first, and you'll hear much more about this
8 during the course of the day is the implementation sequence
9 of the ancillary services market, the day ahead loads market
10 and the special case nodal pricing.
11 The second, and this is a discussion that's been
12 underway way now for almost a year. The ancillary services
13 market conceptual design and in particular the principle of
14 specifying locational reserve requirements, which is one of
15 the more controversial aspects of the proposal and I would
16 like to kind of put that on the table so we have that
17 discussion at some point during the course of the day as
18 well.
19 The third point is the importance of the
20 wholesale markets plan as a tool to bring structure to the
21 market enhancement process and the ISO business planning and
22 budgeting process. I'll elaborate on that point further on
23 in my presentation.
24 (Slide.)
25 I think last year was the second year we

1 published a wholesale market plan and what I put up there in
2 very broad brush strokes. Understand, there is a lot of
3 detail behind each one of these points. What we see as some
4 of the priorities they have been trying to address as we
5 evolve the markets. I think we've made good progress over
6 the last four or five years, but that doesn't mean they are
7 done and there are a lot of enhancements we still have to
8 put into the markets.
9 I list them out on the chart as capacity market
10 enhancements, LICAP, the ancillary services, market
11 enhancement and planned participation in wholesale markets.
12 I'll elaborate on that in a moment. Seams, we just recently
13 filed as part of the RTO filing. A list of various seams
14 activities that we need to deal with and then improved
15 integration of operating decisions and market pricing. And
16 there is a linkage in this last one to the second point.
17 We can't really get at this last problem until we
18 actually have dealt with the second point. That will become
19 more evident as we go into the details during the course of
20 the day.
21 We will seek validation that these are the
22 correct priorities going forward again during the course of
23 this year as we discuss the next integration of the
24 wholesale market plan with our stakeholders.
25 One of the things I want to point out, and I'll

1 come to this a little bit later one, but we have got
2 resource constraints in the organization. As much as we
3 would like to do all of that in one year, we cannot do that.
4 So what we have to do is prioritize how we attack the work
5 that's out there.
6 Typically, if we are forced into a corner, and we
7 have to prioritize between different projects, we'd pretty
8 much take them in that order. Although what we will be
9 doing is our best try and get as much done in parallel as
10 possible.
11 But if you look at that list from top to bottom,
12 the real big impact items are close to the top of the list
13 rather than the bottom of the list. There will be
14 stakeholders in the room that might disagree with that,
15 depending on their viewpoint within the marketplace.
16 What we are trying to do is take kind of a global
17 perspective in terms of the market. I say this so that if
18 there is somebody that disagrees with that, we should try
19 and have them say that during the course of the day because
20 the purpose of a discussion like this is to try and give us
21 some affirmation that we have done the right part. Next
22 slide please.
23 (Slide.)
24 I will very briefly set the stage for the
25 discussion that will come later today. I'll pick on two

1 things. The one is the ancillary services market. The
2 objective is to provide price signals that encourage
3 efficient provision of system and locational operating
4 reserves.
5 To improve market pricing during supply shortage
6 conditions and to enable demands to participate directly in
7 real time energy and reserve markets. I'll elaborate on
8 that last point in a little bit more detail on the next
9 slide.
10 (Slide.)
11 The point I make at the bottom is that a
12 functional ancillary services market is necessary to address
13 uplift costs. We have recently started publishing some
14 reports about certain uplift costs, which are occurring
15 particularly in load pockets like Connecticut and Boston
16 where we are dispatching generation out of merit to cover
17 for certain transmission weaknesses.
18 Those costs are coming through as uplift rather
19 than in terms of the market price. We know it's a problem
20 that needs to be worked on but we need an ancillary services
21 market mechanism to be able to get at that problem. We will
22 hear more about that later on.
23 (Slide.)
24 The next slide lists out the things we're doing
25 in terms of trying to fully include demand participation in

1 wholesale markets. The objective here is to increase market
2 efficiency and reliability through increased participation
3 by demand side resources in the market.
4 There are several initiatives under this topic.
5 Day ahead load response, special case nodal pricing, then a
6 transition to direct demand participation in energy and
7 reserve markets. It's important to understand that our
8 demand response programs today, although they are market
9 oriented, are kind of on the side of the market. They are
10 not fully integrated into the market.
11 We don't commit and dispatch demand resources
12 exactly the same way as we would commit and dispatch
13 generators. And so, I think the ultimate goal here is for
14 us to have that complete equality in the market design.
15 That's where we're headed in terms of the ancillary services
16 market project.
17 (Slide.)
18 On the next slide, I'd like to speak briefly to
19 the wholesale markets plan process. We will again be
20 bringing this discussion to our stakeholders in the next
21 three months or so. The reason for this is that we start
22 our annual business planning process in around the May
23 timeframe, internally within our organization.
24 Because the wholesale market plan drives the bulk
25 of our capital budget, it's very important for us to try and

1 get that in the right priority and the right sequencing.
2 It' also has an impact on our operating budget as well.
3 It's a very key input into our business planning cycle.
4 And so what we want to do is make sure that we
5 have the best possible information that we can get. Hence,
6 once again this year, we will be asking participants to
7 weigh in on how we've laid out that particular plan. We did
8 it last year and we would like to do it again this year.
9 What we would do is bring this plan back to the
10 NEPOOL committee to the MBC, to NECPUC, to the various
11 regional Commissioners in the state and would like to bring
12 it back to the Commission for input as well.
13 We find a convergence between the Commission, the
14 ISO and the stakeholders so we can be as efficient and
15 effective as possible as we roll out these changes. It's
16 also not about efficiency, it's about not introducing or
17 introducing change in a measured and gradual way within the
18 marketplace.
19 We've heard over the last several years from many
20 of our stakeholders that entering into bilateral contracts
21 do need some predictability in the marketplace. I thin what
22 this plan does for us is, it allows us to telegraph in
23 advance where we are headed and allow people to make their
24 financial decisions around this.
25 One of the things I'll be looking for during the

1 course of the day is affirmation, if possible, that this is
2 a sensible way of dealing with this discussion.
3 (Slide.)
4 On page 7, I wanted to quickly cover some of the
5 budget comments. We've sized our capital budget. If you
6 look at our budget in the SMD build years, there is a very
7 large capital budget there. It's really $50 million a year.
8 We've gone through SMD and you'll see the capital
9 budget drop down. It's in this range for the last few
10 years, from about $20 to $25 million. That's our intention
11 going forward this year. We will once again budget the
12 capital budget in that range.
13 We believe that's kind of an optimal budget for
14 us in terms of the sizing of our organization. The number
15 of people we've got within the organization. If we were to
16 go much above that, we'd have to upsize the organization and
17 we would start also generating a lot of internal
18 inefficiencies. We don't think it makes a lot of sense to
19 do that.
20 However, there is an implication from doing what
21 we've just said that we were going to do and that is having
22 to apply constraints on how quickly we can move. Once
23 again, the importance of being able to lay out a sensible
24 sequence that will address the higher value items first.
25 Right at the bottom of that slide, you'll see how we tackle

1 the issue of prioritizing and sequencing the projects.
2 Obviously we do our best to get input from our stakeholders.
3 When we look at it, we look at it first of all in terms of
4 market efficiency because that's where the big money lies.
5 Secondly, in terms of our operation efficiency
6 and effectiveness and the efficiency one is obvious, but
7 effectiveness in terms of us running the system and keeping
8 lights on. That's the next big driver for us. And those
9 two things are sometimes often comparable in terms of
10 importance relating to the marketing efficiency.
11 The last thing we take into account is project
12 implementation efficiency. How to group the various
13 improvements together in order to get the biggest bang for
14 the buck quite honestly as we deliver these projects. Vamsi
15 will spend a lot more time talking about that. So I'll
16 conclude with that. Thank you very much for being here.
17 MR. SIPE: Thanks Gordon. I have very little to
18 add as far as market design. I think that's what the panel
19 is for. I would like to see that I was very pleased with
20 the meeting yesterday that we had. I'd like to thank the
21 Chairman and Commissioner Brownell for taking the time to
22 come and meet with us.
23 I was also very pleased with the outcome and the
24 commitment that came almost before we ask of greater
25 communication between staff at NEPOOL. I think that's going

1 to be extremely helpful and will certainly allow us to be
2 much more responsive. I think the line about me carrying a
3 big whip is so interesting.
4 Generally, they're telling me what they need to
5 get done and that I better get it done. I feel there is a
6 little bit of driving the other side, but that's the quality
7 of our stakeholder process, which I think staff will find
8 upon examination or find upon working with them is very
9 motivated and we understand that we have to live up to the
10 very high standard of the ISO that is serving us, who is
11 very responsive and we have a job to be constructive and
12 responsive. We are going to take that very seriously.
13 With that I think we need to start being
14 responsive and let our panelists talk and get on with our
15 day and give the ISO the information and input it needs to
16 move forward.
17 CHAIRMAN WOOD: Don, it's not the whip they see,
18 it's the bulge they see in your coat.
19 (Laughter.)
20 CHAIRMAN WOOD: We've got here our panel. Hey,
21 Commissioner, welcome. We're glad to have you here.
22 COMMISSIONER JUDSON: Thank you.
23 CHAIRMAN WOOD: I want to remind folks we've got
24 a handout for this next panel that is entitled Roundtable
25 Discussion on Implementation Sequence. There are some

1 copies of that in the back if you don't have them, the folks
2 from the audience. After Vamsi finishes with his
3 presentation, we'll go into that here.
4 Just a housekeeping note. This is being
5 transcribed because there are pending cases that were
6 noticed for this meeting. This transcript will be put in
7 the record of those seven or eight dockets that were
8 mentioned in the notice, which include a number of the so-
9 called "hot" dockets that relate to the ISO. If you could
10 keep any comments you have focused on what we're doing
11 today, which does fall under the posting of those eight
12 dockets, that would be great.
13 If you have some extra comments that relate to
14 those dockets, fine, but if you could make sure any comments
15 you have stay within the confines of those meetings, so we
16 can stay legal. So we want to do that. Vamsi.
17 MR. CHADALAVADA: Thanks Pat. Good morning
18 everyone and I'd like to echo Gordon's thoughts in thanking
19 every one of you for taking the time today.
20 The focus of my presentation is to discuss the
21 implementation sequence for ancillary services markets, day
22 ahead load response and special case notice.
23 Please feel free to stop me at any time if there
24 is any areas of questions or concerns. And I have to admit,
25 that since the fire alarm went off at the Seaport Hotel at

1 2:30, I haven't slept. I think a question or two would wake
2 me up and it will be well advised.
3 (Laughter.)
4 (Slide.)
5 MR. CHADALAVADA: A lot of what I will be
6 covering in the first couple of slides Gordon has already
7 eluded to it. The primary considerations, as all of us well
8 realize, we do have a long list of things we need to get
9 done and the list of priorities is often urgent and also
10 competing in terms of stakeholder priorities.
11 So we want to get as much of this to the market
12 as efficiently and as early as possible, while at the same
13 time to look at the benefits of implementation as well as to
14 take into account the synergies that sometimes these
15 multiple market enhancements have.
16 (Slide.)
17 A equally important consideration is the fact
18 that a delay in the start of the implementation often
19 cascades downstream and starts to impact other activities
20 that have been identified and that's something we look at.
21 So it's not necessarily just a one or a two-year outlook,
22 but we'd like to think that we have the third and fourth
23 year as well.
24 (Slide.)
25 Slide 4, 5, and 6 essentially talk to a very high

1 level of the scope of what the market enhancements are about
2 and further detailed explanation of this will be forthcoming
3 a little later in my presentation. But certainly, the whole
4 afternoon is going to be dedicated to discussing these early
5 issues. So unless there are any questions on this high
6 level scope, I'll go to slide 7, which is where the
7 implementation sequence starts.
8 (Slide.)
9 We have talked about the process of developing
10 the wholesale markets plan as we look through the process
11 and identify the priorities for the 2005 wholesale markets
12 plan and identify the set of activities that we felt was
13 critical for us to get done in New England.
14 And as a result of the planning that follows, the
15 identification of those priorities, we've decided that this
16 would be the original implementation sequence and this is
17 the sequence that was published in the 2005 wholesale
18 markets plan. The cost for the ISO proposed data in those
19 response to be implemented in 2005 and where I have in
20 parenthesis, sequential methodology, essentially links to
21 the method of market clearing we will be talking about in
22 the a couple of slides.
23 The ancillary services market scheduled for
24 implementation in October 2005 and special case nodal
25 pricing also scheduled for implementation in October 2005.

1 (Slide.)
2 We had obviously spend a lot of time looking at
3 the best way to package the functionality and the best way
4 to implement as much of this as early as we could.
5 The rationale for putting together the sequence
6 as we did, was to implement the enhancements early to comply
7 with Commission directors to leverage the synergies that
8 often exist because you are opening up the same set of
9 systems and software for a lot of the changes.
10 There are also dependencies. There is certain
11 sequencing. There are certain sets of functionality that
12 needs to be in place before you can move forward with the
13 next set of market enhancements.
14 Lastly, and equally important, to recognize the
15 benefits and the release methodology for delivering the
16 enhancements to the market.
17 (Slide.)
18 Some of the identified synergies that the ISO
19 believes would result in efficiency gains. If you look at
20 the \market enhancements which talk to essentially the
21 introduction of real time reserve market and to the
22 introduction of direct demand participation and adding
23 dispatchable assets with dispatchable demand and real time.
24 You'll find that a lot of them have commonality.
25 They all need to be modified in the areas of the functions

1 that are listed on slide 9. The scheduling, pricing,
2 dispatch, security, constrain, reliability, assessment,
3 modeling user interface. These are all subsystems that need
4 to have the modifications done.
5 I think you would agree that when you are going
6 to have surgery on an application or a function, you would
7 like to fix all other things once you open it up for
8 surgery. Rather than opening it up, closing it and having
9 to open it up again. It just leads to a lot of wasted time
10 and delays in many aspects of the project implementation,
11 suggesting testing, training and design developing.
12 (Slide.)
13 I've also spoken earlier to the fact that there
14 is a certain dependency and you need to cure that dependency
15 before enhancements can be put in place. This is one such
16 infrastructure dependency. Gordon briefly spoke to a
17 fundamental improvements that we need to make to all of our
18 systems infrastructure, is to introduce a generate asset
19 class called demand. And it's important that those demand
20 is treated in a consistent manner and in a similar manner as
21 supply.
22 Today, we do not have that fundamental
23 infrastructure improvement. And this is also something that
24 cuts across all systems, cuts across all markets, real time
25 energy market, as well as the day ahead market, reserves

1 market, and the forward reserve market as well.
2 Added to that infrastructure dependency that we
3 have within the ISO, I think we will hear later as well,
4 there are some clear improvements that are needed in the
5 area of modeling, as well as metering.
6 The dependency that I speak to essentially
7 becomes a prerequisite and I've listed the enhancements on
8 slide 11.
9 (Slide.)
10 For us to be able to efficiently implement direct
11 demand participation in reserves and real time markets, to
12 be able to implement dispatchable special case nodal
13 pricing, to be able to truly integrate the day ahead load
14 response into the market clearing, we need to make sure that
15 this infrastructure improvement is in place and then we can
16 more efficiently put these enhancements as a superset of
17 that.
18 This improvement is a part of the ancillary
19 services market and because again of the dependency it's not
20 feasible to do these enhancements until that's in place.
21 What I'd like to do is maybe pause at this point
22 and see if there are any questions or any concerns about
23 what I've covered so far?
24 CHAIRMAN WOOD: That's in response to our end of
25 December order on the day ahead load response program, that

1 last point. Is there any way that that demand participation
2 can happen in the market today through the organized
3 structure or does it have to happen outside on a bilateral
4 manner?
5 MR. CHADALAVADA: The demand participation, and
6 Andy will speak to this, we did have currently a lot of
7 demand response programs. The way the demand response
8 programs currently operate, the registration of demand is
9 done as a mainstream market. But the clearing and the
10 dispatch and maintenance of the demand as an asset, if you
11 will, is handled outside of the mainstream market systems.
12 And therefore, what we are proposing to do here
13 is bring it back into the mainstream market systems. In
14 other words, we would have the flexibility to correctly
15 participate in the fact the market clearing, in day ahead,
16 in real time, and in the forward reserve market.
17 CHAIRMAN WOOD: And timing on that Vamsi?
18 MR. CHADALAVADA: We are currently proposing that
19 this be implemented immediately following the ancillary
20 services market and the infrastructure that we are talking
21 to here, we hope it is going to be in place by June 2006.
22 And that's really going to be the second half of my
23 presentation, that talks to all of the dates associated with
24 that. And we will look to implement these enhancements
25 immediately following the delivery of the improvement in

1 infrastructure.

2 COMMISSIONER BROWNELL: So this is incredibly

3 important I think to the two of us. It's been a common

4 theme. June 2006 will be my fifth year anniversary, so it

5 would be really great if that date didn't slide.

6 MR. CHADALAVADA: Point well taken Nora.

7 MR. MEAD: Can I just ask one other question. In

8 your slide, you mentioned the day ahead load response would

9 be a sequential methodology. Is that as distinct from

10 simultaneous? Can you speak to that? What does that mean

11 and why did you decide sequential rather than simultaneous?

12 MR. CHADALAVADA: I think all of us, at the ISO

13 as well within our participants, agree that the integrated

14 approach is the right approach. I think we was trying to

15 comply with the Commission directive to get a program in

16 place prior to the summer of 2005. And the only way for us

17 to very effectively implement that was to use the sequential

18 methodology because of the dependency that I spoke to.

19 If we had not had a dependency, I think we would

20 have been arching towards an integrated load response

21 mechanism for the day ahead part of it.

22 Also, I think it is important to note that we

23 have to be consistent in our markets across day ahead and

24 real time. So when we speak to an integrated day ahead

25 demand response, we need to make sure that in real time, we

1 have the same kind of integration as well.
2 MR. KATHAN: My question on that has to do with
3 what you're doing right now. Demand is participating in the
4 real time markets. What is the asset limited demand
5 providing incrementally that makes it a better more
6 efficient.
7 MR. CHADALAVADA: I'll give you a quick example.
8 Let's walk through the business process. Once an asset has
9 registered, let's talk to so supply for a second. Once a
10 supply asset is registered in the market, it then basically
11 becomes eligible to be put in the day ahead market.
12 There is a set of rules that go into placement of
13 the bid. The asset bid pair either gets created or not
14 cleared or not cleared in the day ahead market, but then it
15 moves from there to reliability assessment. From there it
16 moves to real time. We track it with regards to deviation,
17 with regard to performance.
18 And from real time, it ends up in a multi-
19 settlement process. So it goes through a settlement system.
20 This walk through of the supply asset is currently not done
21 for demand assets. The demand registered but then it gets
22 diverted either to a separate set of systems, if you will,
23 and does not flow in the same direction as a supply asset
24 would.
25 So what we're doing with the introduction of

1 asset-related demand is ensuring that the capability exist
2 to take a physical demand asset bid pair all the way from
3 registration to settlement across all of our complex system
4 databases, user interfaces, bridges and so on and so forth.
5 MR. KATHAN: And the incremental benefit for
6 doing that versus what you have right now?
7 MR. CHADALAVADA: I think the benefits are
8 manifold. Number one, I think we can state that we will be
9 able to dispatch assets demand and supply in real time. We
10 will be able to say that it is truly integrated into the
11 mainstream market clearing. I think we will be able to
12 state the fact that the clearing of the markets will have
13 direct demand participation rather than the sequential
14 methodology.
15 The fact that it is a generic asset class that we
16 are not constraint by whether it's a municipal demand asset
17 or whether it's going to be a different demand asset,
18 industry, for example.
19 So I think we will be improving the state of our
20 modeling as well as the transparency of the markets, to the
21 demand side.
22 MR. VAN WELIE: David, let me just add something
23 to that. Another way to think about it is that at the
24 moment, there is a direct linkage or direct impact by demand
25 on the optimization programs that are running in day ahead

1 and in real time.
2 So you've got an optimization program that's
3 running in day ahead to deal with your unit commitment. And
4 then in real time dispatch there is an optimization running
5 there as well.
6 At the moment, there is an indirect impact in the
7 sense that if we call, a price signal goes out and demand
8 responds, the load drops and of course, dispatch will adjust
9 to that. That's the indirect impact.
10 But it's not been included directly within the
11 optimization programs, and that's where we've got to get it
12 for it to really be treated equally as equally comparable to
13 a supply resource.
14 MR. MEAD: Does that mean that today, if a
15 customer wanted to submit a price bid into the day ahead,
16 especially I suppose the day ahead market, and said I don't
17 want to consume if the price gets above X. Can a customer
18 do that today?
19 MR. VAN WELIE: Yes.
20 MR. MEAD: Is that included as part of the
21 simultaneous optimization?
22 MR. VAN WELIE: Yes.
23 MR. MEAD: It's these other demand programs that
24 you other comments were referring to?
25 MR. VAN WELIE: Right. Typically, what we'd like

1 to get to here is to be able to call on, it should really be
2 transparent to us as to whether we dispatch at peak load,
3 that has a 30 minute response or demand side which has a 30
4 minute response.
5 And we've recently seen that you can have demand
6 response, create a profile that has the same
7 characteristics, or pretty close to the characteristics of
8 peak. So that's what I'm getting at.
9 MR. CHADALAVADA: One clarification to address
10 your question David. Demand can put us in the day ahead
11 market today, but it's not on an asset specific basis.
12 That's the big distinction we're trying to draw.
13 If you take, for example, virtual demand, which
14 has been a part of the market for a long time now, it's not
15 tied to a physical asset. And for us to be able to
16 correctly incent demand participation, we feel that we need
17 to be able to give the opportunity to have the assets
18 specified and then of course have that be effective in terms
19 of the market.
20 (Slide.)
21 I wanted to quickly speak to the benefit of
22 having a system release methodology. Actually, I don't know
23 where Bob Stein is today, but last night he made a comment
24 that everything takes three years. And I would like to
25 speak to him a little bit on that.

1 (Laughter.)

2 COMMISSIONER BROWNELL: Three years would be

3 short in our lifetime.

4 MR. CHADALAVADA: And also, is he here? I'm

5 going to pick on you Bob. There are lots of efficiency

6 gains to be had with regards to packaging functionality into

7 a single software system release. As you know, we do have a

8 pretty involved, complex system and it is important that we

9 develop transparency that we need to provide and the level

10 of certainty that we need to provide.

11 In pricing, we have very good internal control

12 system in place. We just can't slap the systems and say,

13 here it is, which 80% of the time, 20% tough luck.

14 If all of you believe that would be the way to

15 move on, we could cut these cycles down to almost an 80

16 percentile fashion, but multiple releases create the need

17 for additional system infrastructure and human resources.

18 That drives the cost and more importantly, delays the

19 delivery of enhancements.

20 (Slide.)

21 An illustration of that is on slide 13, which

22 talks about the ancillary services market. If it was

23 practiced as one release, it could be implemented. This

24 fall for a price of about $15 million.

25 If we were to break it up as three parts and make

1 those as three separate releases, we will be talking about
2 getting the same functionality to the market, but it will be
3 two years later and twice the cost. That would be, I hope,
4 an illustration of the kinds of benefits we'd recognize by
5 going to a release cycle.
6 I think the ISO would look to discuss with the
7 stakeholders what is the appropriate release cycle. Is it
8 two year, one year? I think as we get into the wholesale
9 market discussion, this should as well be a topic of
10 conversation.
11 (Slide.)
12 The next couple of slides talk to the consent
13 with stakeholders. Why does it take so long to do market
14 enhancements? Why can't we get it done sooner?
15 I've tried to take out a couple of examples.
16 Take the case of a large project such as hourly markets or
17 ancillary services markets, or medium sized project such as
18 regulation markets and the pricing for external nodes.
19 You see on slide 14 the timelines. We're looking
20 at a medium project, taking from between five to nine
21 months, stakeholder process and regulatory approval. The
22 implementation is roughly the same amount of time.
23 So we're talking about 14 to 18 months cycle for
24 a medium sized project. This of course assumes that those
25 are being done sequentially and not in parallel.

1 (Slide.)

2 Slide 15 really tries to break the project

3 implementation phase down into big blocks. To give you an

4 idea of where most of the time is being spent, going back to

5 the same example of a medium size project. It takes only

6 about 10 weeks to really develop the software, but it takes

7 us almost 20 weeks to make sure that it's auditable, that

8 there are internal controls, that it is properly tested and

9 that we have adequate training. Not only to our internal

10 customers, but our external customers as well.

11 Just bare in mind that we have six shifts of

12 control operators and I'm sure Steve would not like to have

13 them all sitting in the training session in the same week.

14 So we will have to start with the first six weeks and there

15 are things we just can't change. Those are just matters of

16 fact. Go ahead Gordon.

17 MR. VAN WELIE: This slide is a good place to

18 make another point that I wanted to make, which is, as we go

19 forward, and I think this is appropriate in terms of our

20 maturity at the moment, I think what we have to be careful

21 about is not committing to that development, that second

22 stage, until we have a fairly high degree of certainty that

23 we've got support for what we're doing.

24 The implication here is, if there a secret about

25 what we are doing, it's going to interject a delay to the

1 process. So let me try and illustrate that with a little
2 bit more detail.
3 If we bring forward a proposal to the market
4 committee of NEPOOL and the participants committee and we
5 get a high level of support, then I think we feel
6 sufficiently comfortable with that high level of support,
7 that we can start marching forward down that path and
8 spending money without necessarily getting FERC approval.
9 You might disagree with that and say that's not
10 what you want us to do, but that at least allows us to get
11 going while you weigh all the various arguments that are put
12 before you. That's assuming a high level of support from
13 NEPOOL. I guess at that point, we can say with our hand on
14 our heart, that that's what our stakeholders largely want.
15 If we have a high level of disagreement and we
16 don't have a lot of support, I'm kind of reluctant to go
17 into that next stage until we hear from you, that that's
18 what you want us to do. That will be a change in philosophy
19 going forward.
20 If you look at the ancillary services market
21 project, we got going with development, we though it was
22 important as a high value item for the pool and for the
23 wholesale market, and so we got going pretty early as far as
24 the development cycle was concerned, so that we could hold
25 that October 2005 date.

1 We've learned a lesson just in the last three or
2 four months, which was, it became clear in the December
3 timeframe that we didn't have the requisite support. So
4 that if we were to have forced the process or force the
5 proposal through the committee process, the NEPOOL process,
6 it would have landed on the Commission's desk, with a low
7 level of support, therefore a high probably of litigation.
8 That doesn't help anyone, because it interjects a very long
9 delay into the cycle at that point.
10 So we're going to do our best to try and get the
11 highest level of support we can for proposals. Ultimately
12 the proposals may be too controversial. In which case, we
13 would have to bring it forward to the FERC.
14 But the thing I want to put on the table that
15 people need to recognize is that we are going to hold off
16 committing a lot of development dollars until we know where
17 we are going, because uncertainty in terms of scope is the
18 single biggest driver in terms of software costs.
19 Assuming you've got competent resource to deliver
20 a project, it's like build a house. If you are going to
21 change the blueprint every two weeks, the costs are going to
22 go up. That's why I want to make this point that we've got
23 to be sensitive to getting the scope nailed down before we
24 can commit the resources and tell the IT folks to go off and
25 start building.

1 COMMISSIONER BROWNELL: Could we emphasize that
2 and underscore that if there is any single lesson that we
3 have learned and will be coming out with a report from a
4 consultant that we hired, Gestalt recently look at that.
5 That is not rocket science. It is very clear what drives
6 these costs from which we are being criticized, and that is
7 indecision, changed orders, delay, filling in the blanks
8 after you've already started the process.
9 And so, I think that we must all be significantly
10 more disciplined than we have historically because this is a
11 lesson we've learned and it hasn't been as big an issue here
12 as it has in other markets, but its an issue everywhere.
13 MR. SIPE: Just to follow up on that because
14 we've had this discussion internally at NEPOOL with you
15 about what level of certainty or what level of agreement on
16 scope allows you to move forward with development.
17 My understanding is in some pieces, if you get
18 sort of a broad level support, you can do some things. But,
19 there is a limited bucket of things that can be done until
20 we actually get some details, almost at the level of market
21 rules.
22 I hope you can share any general thoughts about
23 how far we can go, for instance with a term sheet proposal.
24 How many terms do you have to have filled in before you feel
25 confident you can begin to develop and where you need the

1 details? Is it almost immediately? Further down the road,
2 or are there things you can do that aren't going to have to
3 be redone once you know certain broad shapes.
4 MR. CHADALAVADA: That's a valid point Don and I
5 think the way we'll move forward and I'll be speaking to it
6 shortly. The design of time sheet approach. If we do get a
7 broad range of support on a conceptual framework, that gives
8 us enough to start to build a shell.
9 As the details start to get flushed out, we can
10 start adding details to the shell. Of course, it's probably
11 not the most efficient, but it certainly would be more
12 efficient than if were to do nothing until all the approvals
13 are in place.
14 It's a fine balance there and it is something we
15 would have to be very careful of in terms of observing on an
16 enhancement-by-enhancement basis and it's a frank
17 conversation t hat we will be having with all of the
18 stakeholders. Once we think that, like I said, in terms of
19 the support, we could start taking the initial movements
20 towards the development and design.
21 MR. VAN WELIE: Can I just add to that. In terms
22 of some of the discipline I'd liked to introduce into the
23 process. We will be giving our stakeholders a date, a
24 deadline by which the market rules have to be done in
25 detail. Because in the end, what is software, but coding a

1 very, very detailed algorithm.
2 There comes a stage in these projects you can go
3 a little way to development based on kind of a framework
4 discussion that you can't go very far before the programmer
5 turns around to you and says, I need the specifics because
6 I've got to turn this into a mathematical equation in
7 software.
8 So, to me it is incumbent to us as the ISO and
9 our stakeholders to give certainty to the folks who are
10 going to build this stuff. Therefore, we've got to be
11 disciplined in setting those deadlines and drawing those
12 lines in the sand and not allowing the development process
13 to go very far until we've actually created that certainty.
14 (Slide.)
15 MR. CHADALAVADA: There are so many other
16 questions on that one. We have taken the ISO proposal that
17 I spoke to on the enhancement as well as the implementation
18 scheduled to our stakeholders and we had several discussions
19 about both the proposal and the schedule.
20 Some of the stakeholder feedback and the concerns
21 the ISO received were regarding the correlation between the
22 locational aspect of the ancillary services market and the
23 capacity market. Regarding the complexity of the ancillary
24 services market design. The heavy demand on time cost by
25 the LICAP and RTO in 2004, about the need for a more

1 detailed market impact analysis and the fact that there is a
2 high pace of market design enhancements coming through,
3 which makes it difficult to be able to focus on a single
4 issue.
5 If you're talking about four enhancements in an
6 eight-hour day, it becomes a very tough chore to switch from
7 one to the other. I think the ISO and the stakeholders have
8 had several good discussions over the last several weeks.
9 (Slide.)
10 And we've agreed that we'll come out with a
11 slightly revised process. What we will be ending up doing,
12 is switching to a design sheet approach, really more like a
13 decision tree. Then again, not to pick on Bob now, but I
14 think it was Bob that floated the concept in an email to
15 several stakeholders and it received a high level of support
16 and set the stage for us to move forward in that direction.
17 We would start with the objectives, agree on what
18 the objectives are, and from that perspective, we would
19 publish a series of White Papers. We will have examples
20 that would discuss the conceptual design intended to solve
21 the objective. We would also provide, initially as part of
22 a market design proposal, a more detailed market impact
23 analysis.
24 Then we would have the committees vote on the
25 conceptual agreement. At that point, absence support on the

1 conceptual framework, continue to work on it and would look
2 to the Commission for support.
3 If we do have agreement on the conceptual
4 framework, we would then start work on the detailed design,
5 as well as the market tools toward finishing up the
6 enhancement. This is a process that has actually worked
7 very well since we reverted to it in January.
8 (Slide.)
9 We've taken up this approach for ancillary
10 services market in January. We started having these
11 discussions and decided that a change was appropriate. The
12 change to this revised format has resulted in significant
13 progress being made.
14 I think that we've come a long way in the last
15 couple of months on a lot of key topics and I think the
16 experience that we've garnered over the last couple of
17 months will help build a strong foundation for the ISO and
18 its stakeholders in discussions on future market
19 enhancements. I'm very confident about that.
20 (Slide.)
21 Based on the stakeholder feedback, as well as the
22 discussions we've had over the last couple of months, the
23 ISO went back, reevaluated its implementation sequence and
24 brought back to the committee several alternate proposals
25 for the implementation of these market enhancements.

1 (Slide.)
2 Slide 26, the February NEPOOL participants
3 committee by an overwhelming 96 support level to implement
4 ancillary services market in two phases.
5 Phase one, scheduled for October 2005, will have
6 the regulation market redesign and a couple of other market
7 enhancements that Mark will be speaking to this afternoon.
8 Phase two will be scheduled for implementation no
9 earlier than June 2006 and will include the reserve market
10 design, direct demand participation, both in real time and
11 reserve markets and a special case nodal pricing.
12 (Slide.)
13 Also, at the same NEPOOL participants meeting in
14 February, the committee approved the ISO proposal of a
15 sequential day ahead load response program for
16 implementation by June 1, 2005 and to replace it with the
17 more correct integrated approach. This will be done
18 following the implementation of ancillary services markets.
19 As I indicated earlier, the implementation of the
20 ancillary services market is apparently scheduled for no
21 earlier than June 2006. We hope to be able to finalize the
22 date as we move forward into the next couple of months. Any
23 questions at this point?
24 MR. KATHAN: I have a question. I want to
25 understand on this slide, what does following mean? What

1 dates are you talking about and is it going to be a lengthy
2 period after, immediately thereafter? What exactly are you
3 meaning?
4 MR. CHADALAVADA: It's a good question David. I
5 think we're looking at it from two perspectives. I can't,
6 unfortunately make that commitment to the schedule
7 implementation date for the integrated program, because we
8 haven't flushed out the design details with our
9 stakeholders.
10 When we scoped it out at a high level, we think
11 it's probably a 12-15 months project. If we assume
12 ancillary services market goes ahead in June 2006, we will
13 be looking at the third or fourth quarter of 2007 for the
14 implementation of the more correct integrated load response.
15 That would be a high level timeline.
16 Also, the feedback we've gotten from the
17 stakeholders is that if the Commission were to agree, it
18 gives a couple of years for the sequential program to work
19 its way through the system. For the participants to garner
20 sufficient experience using this program, that might serve
21 the New England stakeholders in good stead when we make the
22 next step.
23 MR. KATHAN: Okay. I guess a follow up to that
24 question is, in slide 20, you talk about having the direct
25 demand participation reserve in real time energy markets. I

1 guess I need to understand what's different about the day
2 ahead versus the direct demand participation in reserve and
3 the real time energy market, makes such that it can't be
4 done at the same time, or that it needs to be delayed for
5 that extra year.
6 MR. CHADALAVADA: The direct demand participation
7 in reserve and real time energy market is exactly identical
8 to the introduction of what I spoke to earlier, the generic
9 asset class called demand. So we would simply be speaking
10 to the infrastructure improvements both in terms of the
11 software systems, databases, user interface as well as the
12 business processes that need to be changed.
13 What it will not speak to is how the market rule
14 is going to be defined. How is this going to interact with
15 all of the other markets. So if you could separate out the
16 fact that you have to put an application, which is really
17 the definition of market rule program as it function on top
18 of the infrastructure, we will be taking care of the
19 infrastructure part as part of the ancillary services
20 market.
21 The application part of it, which is the same as
22 designing and developing the market rules will come later.
23 MR. KATHAN: I'm more confused again. Are you
24 saying that the market rules for direct demand participation
25 in reserves and the real time energy markets will also be

1 delayed after the June 2006?
2 MR. CHADALAVADA: The reserves market is actually
3 being the focus and I think when we implement the reserves
4 market, we are going to be in a position because it's
5 encompassed within the ancillary services market scope. We
6 would have demand that we will be available to participate
7 directly in the reserves market.
8 The infrastructure will exist for demand to
9 participate in the real time market. We'll have the
10 flexibility to implement special case nodal pricing, which
11 is having load settle at normal price and be dispatched off
12 nodally. What we will not have at that point is the bid
13 structure for demand to participate in the day ahead market
14 and then have that same integrated real time demand
15 response.
16 That's the part that we will not be doing as part
17 of the ancillary services market.
18 MR. YOSHIMURA: If I could just add a couple of
19 other things. One of the things going forward that we have
20 to explore is for this new asset class, asset related
21 demand. There is going to be, in order to participate in
22 the reserves market, there will be certain requirements on
23 telemetry communications with the ISO.
24 Demand assets tend to be smaller and more
25 disaggregated than generation assets. So we are also, over

1 the period going forward, we have to also explore different
2 ways of communicating and metering these smaller assets,
3 which may require some additional research and
4 infrastructure changes.
5 And so, one of the things that we are going to be
6 doing going forward is, after we get the ancillary services
7 market going. Part of the real changes we'll have to
8 explore is, at the time we put the ancillary services market
9 forward, we also have to think about how do we get into the
10 smaller assets. What I mean by that is the 100 kilowatt
11 types of load assets.
12 Right now, our demand response program currently
13 is able to handle those. But we are not in position right
14 now to be able to say that we'll be able to handle those
15 small assets. It might be that we have to aggregate assets
16 in order to be able to communicate with our systems. That
17 will require a rule change and I'm sure some of the meter
18 reading folks will be able to speak to some of the issues
19 that go along with that.
20 So there are some additional infrastructure
21 changes that will be explored going forward, from this point
22 forward, but we don't know what that's going to look like
23 because we haven't started the research yet. We have to do
24 some research and decide whether or not we need to do some
25 more work on the rules and the telemetry requirements.

1 MR. KATHAN: All I'm trying to make the
2 distinction is between the participation in reserves market
3 in the energy markets and the day ahead, why cannot they be
4 done at the same time. Is it the size? Is it the minimum
5 size of bids in the reserve markets? That's what I'm trying
6 to determine.
7 I understand there are market rule needs and
8 there are different bids. I'm just trying to find out if
9 some of these things will be done as part of the ancillary
10 services market.
11 MR. CHADALAVADA: I think the important point
12 that the infrastructure improvements that we've talked about
13 make it much more easy for us to bring in the integrated
14 data and load response. From a large project, it
15 declassifies itself to a medium project in terms of
16 implementation because we would have tested the
17 infrastructure. We would have the flexibility.
18 What we would not have had is, what is the bid
19 structure for demands. We are not addressing that as part
20 of ancillary services market. Do you say that the demand
21 has to put in the same parameters as the supply or is it
22 going to be a different bid structure, or are we going to
23 make any modification to our current market rule to enable
24 that to happen? Those are the kinds of dialogue and
25 discussions that are going to happen.

1 But once those are made, I think to be able to
2 turn that around and have that be part of the market query
3 is going to be relatively easy because we will have had a
4 significant upgrade to our ability to do that. Does that
5 address it?
6 MR. KATHAN: That addresses a fair amount of it.
7 MR. VAN WELIE: Let me try to add something to
8 that, coming at it from a slightly different direction. Two
9 things that you heard, the first is that the specific rules
10 for dealing with small assets and small resources and how we
11 deal with the pattern from market rule perspective.
12 The other is the telemetry infrastructure. Can
13 you go back to 20?
14 (Slide.)
15 If you see there, there is two, this is now
16 serving a June 6 implementation, requires us to file
17 something by September and get approval from the FERC by
18 November 2005. that means that in order for example to
19 include in this within the scope of the June 2006
20 implementation, you have to have those rules done by
21 September 2005.
22 Furthermore, you have to have all that
23 infrastructure in place by June of the following year. That
24 work hasn't been done and we don't see that it can be
25 accomplished between now and September. What that does is

1 put us in the position of saying, let's get the basic
2 infrastructure in place so that we can come back to that.
3 We will have, as part of the June implementation,
4 the ability to treat demand equally in the reserve markets,
5 which is quite honestly where, from a market perspective, we
6 have the biggest issue.
7 Going back to my earlier comments, about the load
8 pockets, and the fact that we need quick resources. One of
9 the biggest deficiencies we've got from a physical
10 perspective in New England is the lack of first start
11 resources in the load pockets.
12 The resources that we have aren't flexible enough
13 and they can't respond quickly enough, so we get into this
14 out of merit thing that causes upheavals. That's the
15 problem we've got to solve first. Demand can sill
16 participate in terms of bidding in on the existing basis,
17 it's not that they cannot participate in the marketplace,
18 it's the issue of whether they can participate and be
19 dispatched on an asset-by-asset basis, that will be limited
20 outside of the reserve market.
21 MR. CHADALAVADA: I'm just looking to David to
22 see if that adequately addresses your question.
23 MR. KATHAN: It does. Actually I'd like to drill
24 down one level deeper. I guess it's as good a time as any.
25 In the filing that you just did several weeks ago in the

1 ER04-1255, you gave some cost estimates for how much it
2 would cost to implement the program.
3 I just need a little bit of understanding on was
4 that assuming a total stand-alone cost? Was that assuming
5 any synergies associated with doing the asset-related demand
6 first? That's the thing I just need more information to
7 understand. What's the basis for those costs?
8 MR. CHADALAVADA: That's a good question. The
9 costs that were developed in the integrated load response
10 filing were assuming just a stand-alone. That all of the
11 introduction of asset classes would be done as part of that
12 project and that it would be something we would be doing on
13 parallel, if you will, or ahead of ancillary services
14 market.
15 Those costs would be significantly downward if we
16 were to implement it in a phased manner following the
17 infrastructure improvements as part of ASM.
18 MR. KATHAN: Half, a third?
19 MR. CHADALAVADA: Maybe 40 to 50 percent.
20 MR. YOSHIMURA: I would say it's about 30 to 40
21 percent. Another piece of the cost estimate has to do with
22 a more extensive testing of the day ahead load response.
23 Going back to what Vamsi was saying earlier, when you
24 integrate load response, you now have to open up all the
25 software in all the systems.

1 Once you do that, now you have to test all the
2 software and all the systems together in an integrated
3 fashion in order to ensure that the whole system works from
4 bid to build, the sequential approach of voids having to
5 open up all the systems. All you need to do is test the
6 systems that you've developed.
7 But once you go into an integrated approach, you
8 have to develop the ARD class. That's about a third,
9 roughly 30 or 40 percent of the cost. You have to develop
10 the day ahead program as well. Which is maybe a third of
11 the cost and then you have this big testing piece, which is
12 another big piece, which is roughly another third of the
13 cost.
14 That's what driving the cost of the integrated
15 approach compared to the sequential, which requires less
16 testing and it doesn't require an ARD development.
17 MR. CHADALAVADA: David, maybe one last example,
18 if I may. If you're looking at the fact that we are
19 providing this improvement, and we are going to certainly be
20 testing a good deal of this as part of the ancillary
21 services market, but I think there is a need for our
22 stakeholders to be able play in the sandbox for a period of
23 time. Because until this point in time, they have not
24 placed bids on an asset specific basis on the day ahead
25 market.

1 This would be an experience for those demand
2 assets as well and what we've included as part of the
3 project would be to have a few months where we would open up
4 the sandbox to the participants to start to put in the bids
5 and make sure that we have a sample of what kinds of results
6 we would expect and be more transparent.
7 So that when we do eventually turn it on, people
8 are not going to be surprised by it.
9 (Slide.)
10 The last couple of slides certainly, the
11 implementation sequence, as we have been discussing for the
12 last half hour, depends upon FERC decisions on both the
13 proposals as well as the timing. And also another
14 dependency is with regard to the outcome of the capacity
15 market hearings.
16 (Slide.)
17 The last slide, just to reiterate, several of the
18 messages that Gordon has already talked to. I think it's
19 important for us to continue to strive to achieve an
20 operable balance between being very responsive and also at
21 the same time, try to be efficient with regards to the
22 delivery of market enhancements.
23 We're excited and look forward to working with
24 all of our stakeholders. I think we've had a good couple of
25 months and hopefully we will stay on this extremely positive

track. Thank you all. Any further questions?

MR. MEAD: Could I just ask one question? Back on slide 16, where you were talking about the various aspects of implementation. Technically, when does a filing with FERC occur?

MR. CHADALAVADA: What we've been doing so far, and what we're going to propose that we have a discussion about.

(Laughter.)

MR. MEAD: How about both.

MR. CHADALAVADA: Our approach so far has been that in our desire to get the enhancements we know are possible, we have gone through our development path before we make the filing to the FERC so we can say we are at functional design and well into the development stage of the project.

I think moving forward, we'd like to maybe see if we could have a conceptual framework, present it to the Commission and at this point, I'm ad libing, because we haven't had this kind of clear conversation of our stakeholders, but I think we would be maybe looking to take the same design sheet approach and expand.

Once we have agreement from our stakeholders on a design sheet or a conceptual framework, maybe bringing that to the Commission and hopefully at that point we will

1 implement design and development stage.
2 MR. MEAD: Thank you.
3 MR. CHADALAVADA: Absent any other questions,
4 thank you all again for your time and I certainly look
5 forward to working with you.
6 MS. COCHRANE: The first person listed on the
7 agenda next is Daniel Allegretti to respond.
8 MR. ALLEGRETTI: Thank you. My name is Daniel
9 Allegretti, Vice President of Constellation Energy
10 Commodities Group. I also serve as the Vice Chair for the
11 NEPOOL supplier sectors.
12 I think we've heard some really important points
13 this morning and the concept of system release methodology
14 and I think in particular, the point that Gordon made about
15 the need to take a look at the wholesale market plan as a
16 whole. When we think about the sequence in the project,
17 it's very important because a lot of these things are very
18 much interrelated and it would be nice if everything could
19 be the first priority, but it can't and something has to be
20 first.
21 One of the things that suppliers struggle with is
22 the interrelationships between the spot market and the
23 enhancements that we make to the day ahead and real time
24 markets and the forward markets, the bilateral markets in
25 which we transact. In the restructured electricity markets

1 here in New England, there is a real need for supply offers
2 of load following service, and that includes all products,
3 not just energy, at fixed prices.
4 These types of products are used to meet the
5 standard offered default service and competitive retail
6 supply needs in the restructured New England electricity
7 markets. When we make changes to the various products
8 within the marketplace, those changes can be very disruptive
9 to the forward bilateral markets for these types of
10 requirement services and it's important that we do so in a
11 way that balances.
12 One the one hand, there are certainly benefits to
13 doing enhancements. Load response providers are anxious to
14 see the enhancements because that's fundamental to their
15 business. Certainly, we've seen generators with an interest
16 in the locational forward reserves markets, anxious to see
17 that enhancement because it does indeed affect their
18 business.
19 At the same time, implementing new products can
20 be disruptive and so what we've seen is, when we have a
21 stakeholder dialogue, the give and take of that can result
22 in a discussion about the timing and sequencing that results
23 in compromising the balance of these competing interests.
24 You heard Vamsi mentioned several times when he
25 referred to dates, no earlier than. And that's something

1 that we have emphasized through the stakeholder process is
2 important. Is that we have a no earlier than date, because
3 it allows suppliers to transact in the forward market, up to
4 the no earlier than date, knowing that the product or the
5 suite of products that they are buying, that they are
6 transacting and that they're using as portfolio and hedges,
7 are not going to change.
8 In order to provide the enhancements to day ahead
9 demand response, in special case through pricing. As Vamsi
10 explain, we really need to hang it off some of the
11 infrastructure that's part of the ASM market.
12 The ASM market includes more than just those
13 enhancements, and it will in fact make a fundamental change
14 to the products, and in particular the locational component
15 of the reserves or product is a very major change in terms
16 of what we buy and sell out there in the marketplace.
17 And so, as we have the discussion here in New
18 England and talked about a sequential approach, even if an
19 all at once approach may have made more sense in terms of
20 the efficiency of getting the project done, it's more
21 disruptive to the marketplace. Particularly when you step
22 outside the 20 or 30 percent of electricity that is sold in
23 the spot markets and you look at the 70 or 80 percent that's
24 transacted in the forward bilateral market.
25 So we were very pleased that the ISO, despite the

1 difficult that it caused them, was really willing to sit
2 down, have this discussion with stakeholders. Let's have
3 this discussion with each other and try to work out
4 something, which I was thrilled to see had a 96% support
5 from the NEPOOL stakeholders and was something that the ISO
6 felt comfortable from a reliability standpoint, in terms of
7 managing their processes, that will work well for them.
8 So we were very pleased with the outcome here.
9 We think there was a good balancing of these competing
10 considerations, even if from a pure systems implementation
11 standpoint, it doesn't look like the ideal result.
12 And so, stepping back again and looking at the
13 wholesale market plan and how it affects all the markets and
14 all those dynamics, it's something that's really important
15 to be done. I think vetting these things with the
16 stakeholder process is a good way of accomplishing that.
17 That's what I had to say.
18 MS. COCHRANE: And eloquently said it was. I
19 don't know who wanted to go next. In the package, Bob
20 Weishaar's presentation is next.
21 MR. WEISHAAR: Good morning. I appreciate your
22 attention. I'm going to focus on one specific issue that I
23 have been focusing on for quite some time. That is the
24 issue of nodal pricing. I started out as full nodal pricing
25 and has seen been working to special case nodal pricing.

1 I was intrigued by the discussion this morning we
2 heard Bob Stein's philosophy on implementation that puts a
3 three-year timeframe on issues. Vamsi's timeframe for a
4 medium project is total duration of 14 to 18 months.
5 We're coming up on the three-year anniversary of
6 the time when we first raised the issue of nodal pricing an
7 this fall will be the three-year anniversary and the time
8 the Commission first approved nodal pricing for load in New
9 England.
10 A couple of the comments from the Commission's
11 order. When it first approved that nodal pricing for load
12 was a "key feature of the New England SMD market design" and
13 in that same order, "the Commission considers nodal pricing
14 for load to be a just and reasonable pricing method."
15 What we have seen in terms of implementation is
16 somewhat the concept of inertia at work. I think in the
17 stakeholder process and object at rest tends to stay at rest
18 unless acted upon by an outside force.
19 (Laughter.)
20 And to date, the Commission has given us good
21 guidance and proved that in concept. But I think we may
22 still be lacking that outside force necessary to actually
23 get it accomplished and put it into effect in New England.
24 I also wanted to note that, like I said, we
25 started out at full nodal pricing and we heard a lot of

1 concerns from meter readers and electric distribution
2 companies saying that to implement full nodal pricing for
3 every customer in New England, including the cabin out by
4 the lake is going to be prohibitively expensive.
5 And we have since, backed considerably away from
6 full nodal pricing and we are heading, in a proposal that
7 received overwhelming support, from the participants
8 committee and have since been approved in concept by the
9 Commission, to limit the availability of nodal pricing to
10 the larger, more sophisticated loads, at least at the
11 outset.
12 What I am anxious to hear from other
13 presentations today is exactly what technical impediments
14 still exist to implementation of special case nodal pricing.
15 And I also want to emphasize that a distinction could be
16 made between dispatchable special case nodal pricing, which
17 is a more technologically and technically sophisticated
18 version of special case nodal pricing and non-dispatchable
19 special case nodal pricing, which is simply customers just
20 paying for energy at the price of energy at their node, and
21 not setting up the telecommunications infrastructure that
22 would be necessary to make that asset dispatchable.
23 Like I said, the time for implementation is past
24 due under any of the various timeframes that have been
25 suggested and I look forward to learning of the technical

1 impediments that reportedly still exist. Thanks.
2 MR. MEAD: Can I just follow up. It was my
3 understanding that special case nodal pricing was on this
4 to-do list that was going to be implemented, I guess
5 regionally in mid 2005 and now in mid 2006.
6 MR. WEISHAAR: It was first approved by the
7 Commission back in, I think December 2002. The expectation
8 at that time, based on representations in various pleadings
9 to the Commission, was that we were looking at a 15 to 18
10 month timeframe and the Commission said that it expected
11 nodal pricing to be implemented quarter one, 2004.
12 As you saw in an earlier slide, that was pushed
13 back to October 2005 and now, because it's caught up in an
14 asset-related demand element, the ancillary service market,
15 has been pushed back even further. We are now at no earlier
16 than June 2006. So the timeframe here keeps slipping.
17 CHAIRMAN WOOD: So your concern is why does it
18 have to be linked to the asset-related demand element in the
19 program that David as asking Vamsi about. Why can't you do,
20 kind of, I guess, special case nodal pricing lite ASAP, and
21 then do the more integrated system whenever they do the
22 other changes?
23 MR. WEISHAAR: Right. And I think the
24 distinction could be made if the dispatchable special case
25 nodal pricing, in the earlier presentation characterized it

1 as dispatchable special case nodal pricing being caught up
2 and then more efficiently implemented as part of the asset
3 related demand implementation. We still have the issue of
4 just customers being able to settle at the energy price at
5 their node, which is a non-dispatchable version or element
6 of special case nodal pricing.
7 When the last package was presented to the
8 Commission, I think we characterize it as a White Paper,
9 concept paper, created both options for special case nodal
10 pricing. Both the non-dispatchable option and the
11 dispatchable option.
12 CHAIRMAN WOOD: Vamsi.
13 MR. CHADALAVADA: If I may speak to it and Bob
14 does make an important distinction between the non-
15 dispatchable assets that we'd like to participate in special
16 case nodal pricing and the dispatchable asset.
17 But I think it's also a true statement, that the
18 complexity and the technical difficulties are associated
19 with the implementation of the dispatchable special case
20 nodal pricing. This was something that we had discussed
21 with our stakeholders and I think the concern was that this
22 might delay other priorities such as regulation market and
23 such as the direct participation, such as the sequential day
24 and load response.
25 I think the ISO is open and is flexible and is

1 willing to go back and work with the stakeholders on maybe
2 being able to carve this out and see if a dispatchable then
3 could be died to the ancillary services market, but the non-
4 dispatchable portion of it could be implemented at an
5 earlier timeline.
6 But I think we would like to discuss with the
7 stakeholders about their concerns regarding a potential
8 delay on any of the other market enhancements. And given
9 the large amounts of good discussion we've had, it's
10 important for us to be able to hold to our dates as we are
11 committed to in the current design sheet for ancillary
12 services market.
13 But there is an opportunity here to improve upon
14 that and maybe do more and we will welcome the discussion at
15 the upcoming stakeholder meetings and report back on those
16 discussions.
17 MR. VAN WELIE: Procedurally, we've got a group
18 of problems to deal with in the sense that the broader group
19 of our stakeholders did not want us to split it this way and
20 I think that discussion we've got to bring back into the
21 markets committee and the MBC. I'm interested in hearing
22 FERC's view on this as well.
23 CHAIRMAN WOOD: You know, the stakeholder
24 process, certainly we value a lot, but people's interest too
25 are hurt by allowing the more non-dispatchable program to

1 move forward sooner in the stakeholder group? Are there
2 specific people affected by that program going forward or is
3 it just the broader concern that it's pushing the ISO's
4 attention to that program in lieu of other items on the
5 list?
6 MR. WEISHAAR: I can't speak for the other
7 sectors in the stakeholder process, but I think it's maybe
8 the latter. The fact that implementing special case nodal
9 pricing is perceived as be interfering with the
10 implementation of other projects that they deem to have a
11 higher priority.
12 Like I said, when we put the concepts, and I
13 think we call it a White Paper special case nodal pricing
14 and those concepts received overwhelming support at the NPC.
15 We are just now at the stage of actually implementing it and
16 it seems to be inertia against implementation.
17 CHAIRMAN WOOD: Other thoughts?
18 MR. ALLEGRETTI: I don't perceive it to really be
19 a question of inertia. I think the folks in Holyoke have a
20 lot on their plate. They have $20 to $25 million a year in
21 their capital budget and as I said, at the top of my
22 remarks, we can't make everything the top priority.
23 We've got to sit down and look at a wholesale
24 markets plan and say, there are a whole lot in the
25 enhancements, improvements, good things that we need to do,

1 but we've got to come up with a logical sequencing, we've
2 got to come up with a timetable. We've got to come up with
3 a set of priorities and to do that, we don't want to run
4 over anybody's interest.
5 We need to have a good open discussion where
6 there is give and take, where we can hear from folks like
7 Bob, the importance of special case nodal pricing, how much
8 it's going to mean to different industrial customers.
9 At the same time, we need to hear from generators
10 and what would be the effect on a potential delay in the
11 implementation of locational reserves if that gets bumped to
12 make room for staff resources to implement special case
13 nodal pricing sooner.
14 We get to hear from the ISO about what the
15 competing resource implications are. I think that's why
16 Vamsi was suggesting it needs to go back to the
17 stakeholders. Because I really do think it's unfair to say
18 it's just a product of inertia. I think it's the product of
19 a host of competing priorities that need to be settled.
20 CHAIRMAN WOOD: Don.
21 MR. SIPE: I think this is just one of those
22 examples. I would echo Gordon's comments. It would be real
23 interesting to know what FERC staff and the people who are
24 working on this market think about this.
25 Not necessarily that they are going to be

1 controlling but certainly it's one of those areas where
2 discussion of priorities and where we would like to go,
3 having some of that input into the stakeholder process would
4 be very useful.
5 I think occasionally we act not knowing fully
6 where the priorities may be, where FERC staff thinks we
7 ought to go and other things.
8 This is another one of those areas where I think
9 our plan on future communications can help. But certainly,
10 any inputs you could give us.
11 CHAIRMAN WOOD: Let me take a stab at this and
12 kind of step back to the big picture, why we care. And you
13 will note from David's line of questioning of Vamsi a moment
14 ago about the demand side, one of the things that we
15 discovered in our year preparation for publishing the SMD
16 proposed rule was really trying to find out what is the best
17 market design we could possibly do in the world.
18 And one of the critical elements that shows up in
19 everybody, both the real world people and hypothetical world
20 people, is you've got to have the ability of demand to
21 participate in the market. Not in the kind of kidsy way but
22 in a real way that reacts in real time and as much as
23 possible to prices that could conceive.
24 That address market power, it addresses
25 volatility, it addresses needle peak pricing, it addresses a

1 whole lot of things that we're having to contrive a lot of
2 regulatory artifices to deal with. And as a small peak
3 political matter, we know that even in robust stakeholder
4 processes like you have here in New England, that there is
5 not really someone there with a strong voice for that.
6 Maybe the consumer councils are probably the
7 people outlook to the most to be articulating that. Perhaps
8 some providers of services, but there are not that many of
9 those because there is not an ability to provide that
10 service on a sustainable basis for business.
11 And so we have taken it on ourselves to
12 represent, on behalf of the public, that this thing has go
13 to be addressed. If we're going to get to a market that
14 works good for investors and for customers, for the
15 politicians, for the grandchildren, we've got to put a
16 demand component in here, and it's got to be real, it's got
17 to be a permanent part of the landscape.
18 The people who we know, who can take the most
19 advantage of that on day are the big guys. The buy guys
20 spend a lot more money as a percentage generally of their
21 budget than the homeowner does. So you look first of all to
22 the discipline that comes from the 10, 15, 20, 30, depending
23 on what part of the country percent, that have the ability
24 to respond to price. So that's when we get to the nodal
25 pricing issue. Is because you've got the ability to get a

1 pricing at that node, as opposed to an average price over
2 some region of the state.
3 Those people can react and will react to real
4 time price signals if they get them and if they have to live
5 by them. So those two kind of things are linked and just
6 want to explain why we are interested and why we care and
7 while honestly we will push that one harder because we know
8 that despite how broad NEPOOL and the participants committee
9 is, and while honestly we are thrilled to see that alternate
10 suppliers seat at the table that you all created, that its
11 not really a loud voice and it's one that we know could get
12 nudged aside.
13 So we're going to be continuing to care about
14 that issue not as honestly favoritism of the industrials or
15 to create new business opportunities for the main providers
16 but because that's how you get a real market that works.
17 Then these guys would know the details.
18 (Laughter.)
19 That's the philosophy about why we care. I don't
20 know if that answers Bob's questions but basically can give
21 you a sense of why it needs to be at the front of the table,
22 or on top of the list probably.
23 MR. VAN WELIE: I'll close that off and test if
24 there is a reaction. What I'd like to see us do then is
25 that Vamsi and his team take this back through the process,

1 look for a way of decoupling the special case nodal pricing
2 in two pieces.
3 The easier piece and the harder piece, and then
4 see how we can get the easy piece done as soon as possible.
5 Anyone have objection to that as an approach?
6 MS. GONDEK: One thing I would like to add to
7 that is, I'm going to be speaking about the assigned meter
8 readers for special case nodal pricing. Certainly one of
9 our biggest issues is to determine what the design details
10 area so that we can determine and then commit to an
11 implementation date.
12 COMMISSIONER BROWNELL: Maybe Vamsi if you would
13 include the really smart team here, to work with you on
14 those details so as we're developing whatever alternative
15 comes up, we're kind of all on the same page.
16 MR. CHADALAVADA: Absolutely.
17 COMMISSIONER BROWNELL: Thanks.
18 CHAIRMAN WOOD: Okay, Carmel.
19 MS. GONDEK: My name is Carmel Gondek, an
20 employee of Northeast Utility Services Company. I'm here
21 today to speak on behalf of the New England host participant
22 assigned meter readers.
23 (Slide.)
24 The host participant assigned meter readers are
25 those who provide meter-reading services on behalf of the

1 distribution and transmission companies in New England. And
2 our comments today are specific to the implementation of
3 special case nodal pricing from the assigned meter readers
4 perspective.
5 The host participant assigned meter readers
6 provide viable services in support of the wholesale market
7 by providing and satisfying certain settlement data for ISO
8 New England's use.
9 We serve as the meter reader for many of the
10 demand response program assets. We provide the daily ICAP
11 obligations for all of the suppliers.
12 We also supply the majority of the generation
13 asset volumes as well as hourly load volumes for the load
14 obligations for load serving entities throughout New
15 England. An ISO as you know, uses this data for settlement
16 and settles it at a zonal level.
17 With the implementation of special case nodal
18 pricing, the meter reader services will need to expand to
19 also include special case nodal pricing load asset value.
20 What that essentially is is a separate asset for each
21 individual end use customer that is participating in the
22 special case nodal pricing program.
23 In the package, the handout package, there is a
24 sheet of paper that lists out, and what's entitled SCNP
25 implementation.

1 (Slide.)
2 It details what the host participant assigned
3 meter readers' understanding is of special case nodal
4 pricing eligibility criteria. And the host participant
5 assigned meter readers are currently preparing to support
6 the implementation of SCNP with those understandings. So I
7 encourage you all to take a look at that.
8 Much of the details that are on that sheet --
9 actually there they are -- much of the details on that sheet
10 are consistent with the FERC order that came out in
11 December. The meter readers fully support implementation of
12 this program, based on our current understanding.
13 However, as stated on the next slide, there are
14 really some concerns that we have about the design details
15 which could not yet be determined.
16 (Slide.)
17 The meter readers are anxious to work with ISO
18 New England to develop the specific market roles and program
19 design details that address our primary areas of concern,
20 which is the eligibility notification process and ensuring
21 that the customers meet the eligibility criteria and they
22 are actually mapped to the appropriate pricing node.
23 That the asset registration and the customer
24 enrolled with the process matches the customer enrolled by
25 the registered supplier operating the SMP, that its matched

1 to the right asset so that in the financial settlement, it
2 will be priced appropriately.
3 There is also some concerns about the timing and
4 frequency of updates to nodal mapping. How do we handle a
5 customer who may electrically mapped to or rerouted to a
6 different pricing node? We need to make sure that the lead
7 time for installation of the metering equipment is fully
8 identified so that all the market entities needs are met.
9 We need to also make sure that we establish the
10 appropriate policing of customer load to the load asset so
11 that the right customers are being priced for the right
12 location.
13 And very important to us is the effective changes
14 the eligibility criteria to the system and business process
15 that we have in place to support this.
16 ISO New England has agreed to develop a
17 subcommittee of the meter reader working group so that we
18 can start to address these important details. Once these
19 program details have been established, we will be able to
20 identify and commit to an implementation date.
21 As I mentioned before, we are very anxious to
22 determine these program design details so that we can
23 support this program in an efficient and streamlined manner
24 and not develop a program that may inadvertently create
25 barriers to market participation.

1 We heard a little bit this morning about asset
2 related demands and from the meter readers' perspective,
3 this is still largely undefined. The metering, the
4 enrollment and the meter reading services will be more
5 complex than that special case nodal pricing. So again, in
6 the area of asset related demand participation, we are very
7 anxious to assist the ISO in developing those program design
8 details so that we can support them from a meter reader
9 perspective.
10 I thank you for allowing me the opportunity to
11 speak on this important matter on behalf of the meter
12 readers. Thank you.
13 CHAIRMAN WOOD: Thank you Carmel. Any reaction,
14 response to Carmel?
15 (No response.)
16 CHAIRMAN WOOD: All right Paul.
17 MR. PETERSON: My name is Paul Peterson. I'm a
18 Senior Associated with Synapes Energy Economics, which is a
19 Cambridge, Massachusetts consulting firm and we represent
20 several participants in both the end user sector and the new
21 alternative resources sector, as well as some other
22 stakeholders.
23 My comments today are specifically endorsed by
24 three state consumer advocate agencies, the Connecticut
25 Office of Consumer Counsel, the New Hampshire Office of

1 consumer Advocate and the Maine Office of the Public
2 Advocate.
3 I have three quick housekeeping items and then
4 I'll get to the remarks on the slide. First, I want to
5 acknowledge FERC, and particularly Chairman Wood and
6 Commissioner Brownell's strong and consistent support for
7 demand resources participation in wholesale markets. We
8 will have more of an opportunity to discuss some of those
9 details in the afternoon session.
10 The second item is, I think that everyone in this
11 room is very remiss in not welcoming Chairman Wood and
12 Commissioner Brownell as well as the FERC staff to the home
13 of the current baseball and football world champions here in
14 New England.
15 (Laughter.0
16 CHAIRMAN WOOD: And I won money on both of them,
17 just to let you know.
18 (Laughter.)
19 MR. PETERSON: You're a smart man. And I hope we
20 will have some future additional meetings and perhaps we
21 could work in an excursion at Fenwick park and take in a
22 ball game.
23 The third housekeeping item is, I know I'm the
24 last speaker before lunch, so I want to move through my
25 remarks and get downstairs as quick as possible.

1 It was about ten years ago when NEPOOL began
2 discussions to consider the creation of an independent
3 system operator, largely in response to FERC Order 888. I
4 attended some of those early meetings and one meeting in
5 particular stands out in my mind.
6 It was an evening meeting with a half a dozen
7 senior NEPOOL people and a few NECPUC commissioners.
8 Commissions. I was attending the meeting on behalf of the
9 Vermont Public Service Board. There was also a gentleman,
10 from the law firm of Ballard Spalor, who was attending on
11 behalf of the as yet unformed ISO.
12 At first I thought it was it seemed odd that
13 unformed entity would have an attorney present. But the
14 more I thought about it and as events unfolded, it was
15 absolutely appropriate.
16 That's because one of the early contentious
17 issues was the degree of independence the ISO would have in
18 relationship to NEPOOL. NECPUC achieved and the commission
19 approved in 1997 an interim equal ISO agreement. It
20 provided what was thought to be sufficient independence at
21 the time for ISO New England.
22 In 1998, I left the Vermont Board and took a
23 position with ISO New England, in charge of Regulatory
24 Affairs. This was before ISO New England had a general
25 counsel or Legal and Regulatory Affairs Department.

1 Barely a year old, ISO New England was focused on
2 initial implementation of competitive wholesale markets in
3 trying to establish and confirm its independence from
4 NEPOOL.
5 Today, ISO New England is an RTO. The interim
6 agreement has been replaced by a renewable long term
7 arrangement that firmly established ISO New England's
8 independence in Section 205 filing rights, pursuant to the
9 Federal Power Act.
10 The new uncertainties, that I'd like to speak to
11 you about today, is how ISO New England will be held
12 accountable to both the Commission and to the regional
13 stakeholders, including NEPOOL. You have initiated a Notice
14 of Inquiry, RMO4-12, regarding certain accountability
15 issues, regarding RTO budgets, cost efficiency and rate
16 review procedures.
17 Today's conference is looking at market designs
18 and enhancements. And I would suggest that these are issues
19 that require accountability as well. Despite complaints
20 about the seeming internable equal process, a process that I
21 have participated in from a state regulatory ISO and NEPOOL
22 participant perspective. I concur with the candid comment
23 from a senior ISO official, "if NEPOOL didn't exist, we
24 would have to create it."
25 My final comments for this technical conference

1 focus on the need for the ISO to provide an analysis of the
2 rational for an estimated cost impact of all market changes.
3 It is a pretty simply request that the ISO has complied with
4 in the past and has only recently in the negotiations for
5 the AMS enhancements have agreed to provide these proposed
6 changes.
7 I urge you the Commission to confirm the
8 appropriateness of providing this data cost impact for
9 market changes and to require such information before the
10 commission.
11 NEPOOL participants as well as stakeholders in
12 other ISO RTOs have been mischaracterized as narrow minded,
13 exclusively pocket-book focused entities. It is true that
14 generators are interested in how a market change will affect
15 their earnings, and that load entities are interested in how
16 market changes will affect cost for their customers. It is
17 also true that ISO New England needs their comments and
18 feedback for both load and generators to determine if
19 proposed changes are really going to achieve the goal of
20 improving the sustainability and competitiveness of the
21 wholesale marketplace.
22 Generators need to know if the new reserve market
23 proposal is actually going to provide them with appropriate
24 compensation for the reserve services they provide, and when
25 they provide it.

1 Load interest need to have some assurance that
2 the new rules will not provide payment for the same service
3 twice or will provide opportunities for market manipulation.
4 These are appropriate and necessary checks and balances by
5 stakeholders on an RTO's independence and the RTO's
6 appropriate lack of involvement in the financial outcomes of
7 markets.
8 They are key elements of the overall goal of
9 providing reliable electric service and a just and
10 reasonable total cost. I encourage you as FERC
11 Commissioners and staff to ensure the stakeholder processes
12 are robust and meaningful and the need for RTO independence
13 is balanced with the need for accountability to individual
14 stakeholders.
15 I was very encouraged by comments I had with Don
16 Sipes this morning regard last night's conversations and I
17 understand the Commission has been very supportive of the
18 need to accommodate the NEPOOL stakeholders in robust and
19 meaningful process with all other parties that are
20 concerned.
21 Thank you for this opportunity and I will be
22 happy to respond to any questions.
23 CHAIRMAN WOOD: I just want to add one thought on
24 that. Thank you Paul for that. Thanks for the perspective
25 of history as well. It's something we always sometime give

1 a short thrift to and shouldn't because we always are doomed
2 to repeat it of we don't remember it.
3 One of the points that came up yesterday in the
4 discussions about the stakeholders and the role that the
5 more enhanced role that we want our staff to pay, is really
6 an early warning for us that we know what the issues are
7 before they come to us and we love stakeholders because of
8 the kumbaya aspect, certainly, but let's be realistic, we
9 love it because we make our jobs easier.
10 When you take 100 issues and you've only teed up
11 three or four for us to really noodle into and decide and it
12 still takes us a while to do. Imagine if we had to do the
13 other 96. So there is a little self interest involved in
14 why we want to see this process done but it can be a lot, I
15 think. What we care about is the people who have to vote on
16 these things and have to look at the legal findings that we
17 have to make. These guys are very deeply involved and
18 understand what we are interested in and what we have to do.
19 So injecting them more as Don and the leadership
20 asked us to do yesterday, is not only a self-serving benefit
21 for us, but hopefully will be more useful as you guys --
22 this is exactly the way you should run a business. I've
23 told Gordon this before, but you do a big picture plan.
24 This is what we are about. We do this at the Commission as
25 well. This is a big picture about what we are about.

1 Then you come back with what we're doing today,
2 which is you get to lay down the funnel and then you
3 translate it into tariff languages. It would be nice along
4 that way to make sure everything that could be conceivable a
5 problem, gets flushed out. And I think we're hearing a
6 couple today and we'll hear some more the rest of the day.
7 So that when it comes to us, we can turn around
8 in 60/90 days. And then the software guy can get with Vamsi
9 and they can start cranking through the 40 or 60 week
10 process that they laid out up front.
11 That is a smart way to spend the people's money
12 because that's whose money we're spending here and we've got
13 to spend it thoughtfully and mindfully so that they get
14 benefits from what we're doing.
15 But you're right and I appreciate the concept.
16 We haven't really responded to it yet, Gordon, but since
17 you're the last speaker, I wanted to do that before lunch.
18 This is how you run a good business.
19 This is how the best businesses, both government
20 agencies and private agencies that I'm aware of and pay
21 attention to running, is they tell people where they're
22 going, they involve everybody, as you're doing here today,
23 and have done at all the meetings leading up to today, in
24 getting flesh to those bones.
25 Then you get a full corpus together and send it

1 through the process, get the validation, hopefully having
2 gotten a lot of validation along the way so that there is no
3 surprises and that's what I want these guys to be a lot more
4 about.
5 Then be efficient with those resources and get
6 these done on time and under budget. I think it's what the
7 people out there want us to do. So thanks for kind of being
8 the last guy around the track today because that's a good
9 reminder.
10 MR. PETERSON: Chairman Wood, if I could, I want
11 to emphasize that I call this kind of a new process that
12 developed over the last few months, where we're working on
13 this term sheet, the ISO has agreed to provide the cost
14 estimate impact that I'm suggesting by May, and this is for
15 the proposal that we're going to be discussing and vetting
16 over the summer and hopefully get rules ready by September
17 that get filed with the FERC and allow implementation next
18 June.
19 This is the earliest in my memory, the earliest
20 in the process that the ISO has ever committed to kind of
21 come up with, in essence, and is holding their feet to the
22 fire that this is precisely what a particular program is
23 going to cost. And I think this is a clear example of a way
24 it shows.
25 CHAIRMAN WOOD: It's a good lesson. Now, Vamsi,

1 you came here about a year ago?
2 MR. CHADALAVADA: Yes.
3 CHAIRMAN WOOD: And I think having somebody like
4 you, I mean I'll do it in front of all your colleagues here,
5 but with your background and expertise, the ability to
6 actually give an honest answer to what Paul and Bob and the
7 people who are paying the bills want to know, is having
8 somebody whose job is focused on the reality check of
9 translating power engineering issues and market issues into
10 software and the timeline.
11 So it is tough for an entity to give an honest
12 answer if they honestly don't know. Getting good people and
13 a good team on board is pretty critical and it's a very good
14 lesson I think for the other ISOs who have varying aspects
15 of expertise there in that critical area on staff, as
16 opposed to farming it out.
17 Certainly because the outside vendors are an
18 important part of this whole exercise, but having people on
19 staff here and really running the show, can give you an
20 honest answer is critical. So good for you for hiring him
21 and I'm glad you said yes.
22 (Laughter.)
23 CHAIRMAN WOOD: Are we lunch-oriented now? Now
24 the afternoon, why don't you tape the afternoon so we can
25 kind of digest that before we come back to it. It will be

1 the rest of the packet, correct.
2 MR. VAN WELIE: I can probably just give you 30
3 seconds here. What we want to do is to go into much more
4 detail and discussion about the ancillary service and so
5 we've got a fairly detailed package and Marc will take us
6 through that and hopefully we will all be able to expose
7 where we've got agreement and where there are still some
8 areas that we need to work on to get agreement.
9 CHAIRMAN WOOD: Okay. Sara.
10 MS. MCKINLEY: Mr. Chairman, my understanding is
11 that the lunch will be in this room and they are going to
12 wheel it in momentarily.
13 CHAIRMAN WOOD: Okay. For those of you who are
14 making other plans for lunch, why don't we start right on
15 time at 12:45 so we can have a full afternoon discussion on
16 the ancillary service details. Thank you all very much.
17 (Lunch break at 11:55 to 12:55)
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1 A F T E R N O O N S E S S I O N
2 CHAIRMAN WOOD: We will go back on the record.
3 We will talk now for the balance of the afternoon about the
4 conceptual design of the ancillary services market. After
5 dealing with some of the general matters this morning, we've
6 got Charles Ide from the Markets Committee Chair of ISO New
7 England and Eric Stinneford, Marc Montalvo as well sitting
8 over here so I'm going to turn it over to you gentlemen for
9 kicking this one off.
10 MR. MONTALVO: Good afternoon.
11 (Slide.)
12 I want to thank you all for this opportunity to
13 spend some time describing the work we've been doing on the
14 design and development of the ancillary services market
15 project and the work we've done thus far with our
16 participants, which I think is very good work and I think we
17 have reason to be proud. What I want to do this afternoon
18 is take you through he conceptual design.
19 (Slide.)
20 Of the various elements and hopefully we can open
21 up discussion of these things so we can have a more
22 comprehensive understanding of where we are today in the
23 design and development process.
24 The ancillary service market project is a project
25 with a lot of components. The major components include

1 changes to our regulation market, changes to the reoffer
2 period, changes to the way we allow external transactions to
3 set price.
4 Most importantly, major changes to our reserve
5 markets, that is enhancements to our own reserve market,
6 which is in place right now, and also the introduction of
7 the real time jointly optimized energy and reserve pricing
8 mechanism.
9 And then ultimately, it's the addition of this
10 asset related demands that is to allow demand assets to
11 participate directly inside our markets on par with
12 generating resources.
13 (Slide.)
14 As has been previously discussed, the project was
15 broken into two phases. Phase one, which is currently
16 scheduled for implementation 1 October of this year, include
17 the regulation market changes, the changes to the reoffer
18 period and also the changes to the external transaction
19 price setting logic.
20 (Slide.)
21 Quickly going through what these design changes
22 are for phase one. First of all, we have a regulation
23 market in place right now. The regulation market we have
24 was part of the PJM SMD package that we implemented a couple
25 of years ago now.

1 Experience with that regulation market has shown
2 that the regulation market design that we had in place under
3 the internal market is in fact superior, and we and other
4 participants have decided to go back to a design that is
5 more like that.
6 Quickly, what this means is that regulation
7 clearing prices rather than being set day ahead would
8 actually be set by the resources providing regulation in the
9 hour in real time. The regulation payments will be composed
10 of a regulation reservation component, a mileage payment.
11 That is a payment for the amount of regulation service
12 provided inside of the hour of the actual movement on AGC.
13 There will be specific regulation opportunity
14 cost awarded to any resource that has to move off its
15 optimal dispatch point in the energy market in order to put
16 it inside of its regulated range to provide regulation.
17 As of today, the self-schedule of regulation will
18 be allowed.
19 CHAIRMAN WOOD: How much of that goes on today
20 and what percentage of the market is self scheduling and how
21 much is provided health wise, in ballpark?
22 MR. MONTALVO: Actually not 100% certain.
23 CHAIRMAN WOOD: Quarter?
24 MR. MONTALVO: I was going to guess half, then I
25 would have been in the middle. 40 to 60 percent on an

1 hourly basis is self-scheduled.
2 (Slide.)
3 MR. MONTALVO: We can skip this one.
4 (Slide.)
5 I think the way we were going to go -- actually
6 can you just go back to that one, I'm sorry. I think the
7 way we wanted to proceed with the presentation is, several
8 of the folks from the participant community are also going
9 to be responding to a bunch of the design elements and as
10 opposed to me rambling through all of the elements for the
11 next hour and a half, that's certainly putting you all to
12 sleep.
13 I thought I would take a break at the end of my
14 description of the elements and the participant that is
15 going to speak to that element, this opportunity to make his
16 remarks. Then we can move on to the next. Is that
17 acceptable to everyone?
18 CHAIRMAN WOOD: That's fine, no problem.
19 MR. MONTALVO: All right.
20 MR. STINNEFORD: We'd asked Joe Staszowski to
21 offer his comments with respect to the regulation markets.
22 The Select Energy that Joe represents here is one of the
23 larger providers of regulation service and is very
24 instrumental in moving this forward. I asked Joe to give us
25 his perspectives.

1 MR. STASZOWSKI: Thank you. From a participant's
2 perspective, I'd just like to give you our thoughts on this
3 change.
4 (Slide.)
5 As you well know, NEPOOL is a very diverse group.
6 It is not shy in voicing its opinions on different topics.
7 On this topic, over 96% of the NEPOOL participants are
8 totally in favor so I think we did get this one right.
9 This regulation market was a market that is
10 almost like back to the future here. We had it in place, it
11 was working fine, but because of the urgency to implement
12 standard market design, the PJM platform that the ISO
13 modified to create the standard market design did not have
14 the same functionality as the market that was in place up to
15 that point.
16 So the participants agreed that it wasn't
17 warranted or it wasn't a good move to delay standard market
18 design to add the regulation feature, so regulation was
19 delayed.
20 At that point, several participants, including
21 Northeast Utilities, requested to the FERC, and I believe
22 the FERC ordered that they wanted to understand how the ISO
23 was moving forward to implement the regulation changes that
24 were in the market before standard market design.
25 I think that's what we have here today. This

1 market is very similar as Marc said to the market we had
2 before standard market design. It will incent the quick
3 response of regulation units such that the ISO will have the
4 control that they need to maintain tide line flows and
5 provide the system regulation that the need for power system
6 changes.
7 The phasing of this ancillary service project
8 were partly ancillary service market will be in October of
9 2005 and the remainder in 2006, we believe is a very prudent
10 move. It allows the ISO to implement something that they
11 understand the scope and they can work toward and get it in
12 place in October. That leaves them a bit more time to work
13 out some of the remaining details for the phase two changes.
14 We are very pleased that they were able to make
15 this change and implement what they could in 2005 and then
16 take the necessary change to work out some of the remaining
17 issues with the phase two issues, which you will hear about
18 later. Thank you.
19 MR. STINNEFORD: Originally, we had Tom Kaslow
20 who was going to offer some comments on this. Tom could not
21 be with us today but Pete Fuller will be providing his
22 comments on this.
23 MR. FULLER: I first mostly want to just express
24 on behalf of Tom his disappointments and regrets for not
25 being here today. He is engaged, as most of us are, in

1 certain proceedings that are happening in Washington and he
2 was unable to get himself away from that today.
3 For those of you who know Tom, I will be briefer.
4 (Laughter.)
5 MR. FULLER: And perhaps I'll stop there.
6 (Laughter.)
7 MR. FULLER: I do work with Tom. I just want to
8 report, and I will not go into the depth that the topic
9 deserves, but as Joe reported and Marc did, the regulation
10 changes that are before us are highly desired by pretty much
11 everybody across the pool. It's a very popular item.
12 There is, however a nagging issue way down in the
13 details of how it's done and the disconnect between how
14 resources are selected to provide regulation and how the
15 pricing is then determined. And there is a sense or an
16 observation that, be it large or small, and I personally
17 don't have a good sense of the magnitude, that the
18 methodology that is proposed and this details,
19 institutionalizes to some extent an uplift payment where
20 many forward market participants would prefer to see it as
21 much as possible, or more so, in a pure market price. That
22 was the entire compensation back and forth.
23 That's the core I think of the issue that Tom
24 would have expressed had he been here.
25 MR. MEAD: I don't want to interject questions

1 until the discussion of regulation is done. Could you
2 further elaborate on this uplift that you present?
3 MR. FULLER: I'll try. The methodology for
4 choosing which resources are economic and the way they fall
5 in the stack of offers available to provide regulation
6 includes both the offer price of the unit of the service
7 that it will be providing and an opportunity cost, based on
8 the fact that it would not be what would otherwise be its
9 economic dispatch price for energy.
10 So that is factored into how units are selected.
11 The pricing is based only on the offer, not on the
12 opportunity. So to the extent a unit is selected that has
13 an opportunity cost, that is paid as an uplift. So that
14 disconnect is disconcerting to some market participants.
15 MR. MEAD: Can I hear the view for why it was
16 done that way?
17 MR. MONTALVO: Sure. The selector logic
18 incorporates several components. At the top of the hour
19 when the operators are looking into the hour to determine
20 what resources might be needed to provide the regulation
21 service, they will look at the set of resources that have
22 valid regulation offers.
23 What those offers are is going to be megawatts of
24 automatic response rate and a dollar per megawatt offer for
25 providing that response capability. But that information is

1 going to be looked at in the following way.
2 First of all, the offer will be put into the
3 formula to the extent to that particular resource needs to
4 be moved off the economic dispatch point to put it into its
5 regulating range in order to provide regulation.
6 The cost associated with doing that either as
7 lost opportunity energy market or fuel expended not
8 recovered through the energy market would be put into that
9 analysis.
10 A change in overall system production costs that
11 results from the moving of resources off their optimal
12 economic dispatch will be put in there and analysis for
13 look-ahead penalty that is to the extent you pass a price
14 break in the energy blocks that have been offered would be
15 assessed and put into.
16 All of that information will be taken and divided
17 by the megawatts of regulation capability offered by that
18 resource to develop a dollar per megawatt of regulation
19 capability rank of price for each resource, and that is the
20 way the resources will be ranked.
21 That ranking will then be provided to the
22 operators. The operators will select the lowest cost set of
23 resources out of that ranking to provide regulation in the
24 hour.
25 Inside of the hour a resource that is on

1 regulation, providing regulation service will be paid the
2 price of the highest cost that is offered price resource
3 that is selected in the five-minute intervals price.
4 So if there are five resources offered with
5 offers which range from $1.00 to $5.00, $5.00 would become
6 the regulation clearing price to the extent inside of the
7 hour, there were any resources that incurred, regulation
8 opportunity costs. That is, resources were moved off of
9 their optimal economic dispatch point in the energy market.
10 Any costs there will be compared to the LMP
11 integrated at the end of the hour to calculate an uplift
12 payment which will then be made to that particular resource.
13 And we believe that the ranking process that we
14 have here actually allows us to provide to the operators a
15 very good estimate of the cost of regulating resources
16 available to it in the hour, allows the operators to make
17 good decisions about what would be the lowest cost set of
18 resources.
19 But also doesn't in any way constrain the
20 operations, that is, to the extent there are transmission
21 constraints or what not on the system, which would cause
22 them to choose resources out of rank order, if you will,
23 they still have that discretion.
24 Most importantly, unlike today where the
25 opportunity cost is made based on a forecast, the

1 opportunity cost will be paid to these resources, to the
2 extent they are incurred, will be based on the actual cost
3 being incurred, much like any output paid in our energy
4 market is today.
5 We don't take uplift today to resource and
6 provide energy in the market based on an estimate before the
7 hour of what the uplift might be. It's based on actual
8 uplift cost as a consequence of actual dispatch and
9 operation. So it is analogous in that way.
10 I think it allows us to get the best set of
11 resources on and it also allows us to compensate them
12 properly.
13 MR. MEAD: The question I would have is, usually
14 you think that the marginal cost of providing regulation is
15 a combination of the offer price and the opportunity cost.
16 In other markets you pay all suppliers the full marginal
17 cost of the most expensive unit that's used for whatever
18 that service is.
19 Here you seem to be departing from that
20 principle. I need to think further whether deregulation is
21 a special case of not.
22 MR. STINNEFORD: This is probably the issue that
23 has required the most Committee discussion to date with the
24 ancillary services market discussions that we've had since
25 we embarked on this design document methodology.

1 Many of the markets would agree with you that we
2 should be striving toward that, but there are some real
3 impediments to doing this as Marc points out. In order to
4 have a regulation clearing price that can be posted in real
5 time or near real time, you can't incorporate those
6 opportunity costs in that real time price, because they are
7 determined long after the fact.
8 We haven't ruled out as a committee or as an
9 organization looking at refining that down the road. In
10 fact, we specifically left that open. This was the only way
11 that we could move forward and meet the October deadline.
12 So the design document the Committee has approved
13 adopts the methodology that Marc has described for initial
14 implementation, leaving open a possibility that we could
15 revisit that down the road and find other ways to deal with
16 opportunity costs.
17 MR. BRENNAN: I wanted to add something. I agree
18 with everything Eric just said, but if we ever get there,
19 where we are able to properly reflect some of the
20 opportunity costs and the clearing price, it's important in
21 the details exactly how you do that.
22 For instance, let's say the offer price of the
23 unit was $5.00, the regulation clearing price, including
24 opportunity costs was $10.00, and this particular unit also
25 had a remaining, or an initial estimated opportunity cost of

1 $10.00. We've got a $10.00 clearing price and a $5.00
2 offer. To me you've made $5.00 there that should be
3 credited toward the remaining uncovered opportunity costs.
4 And that example I would say you might consider
5 adding $5.00 to the clearing price to represent the
6 remaining uncovered, kind of like the net commitment wherein
7 compensation calculations when you look at the total sum of
8 the two. What remains uncovered is yet opportunity cost and
9 you add that to the clearing price.
10 I think Tom might disagree. He might say,
11 regardless of how much you made from the clearing price, you
12 would add the full $10.00 opportunity cost to the price.
13 MR. MEAD: One other question I see that one of
14 the changes is to go from a day ahead price to a real time.
15 I gather there are not two settlements. Is the possibility
16 of having both the day ahead procurement and real time
17 procurement. Is that considered a desirable thing?
18 MR. MONTALVO: No.
19 MR. MEAD: Given that unit commitment decisions
20 would factor in not only energy costs but ancillary service
21 cost. What's the rationale for not considering regulation
22 procurement in the day ahead commitment?
23 MR. MONTALVO: Regulation is a real time service.
24 It's used in order to ensure frequency control and balance.
25 None of those factors apply in the day ahead clearing. We

1 don't have frequency controls that we concern ourselves
2 with, we have a bid in demand and it is what it is.
3 There are no fluctuations. We have our scheduled
4 tie flows in the day ahead. They are what they are. There
5 are no deviations from that. So what is the service day
6 ahead that's actually being provided.
7 MR. MEAD: You know that you need some capacity
8 in day ahead. You need some capacity that will be
9 designated to provide regulation of service. Wouldn't you
10 want to consider that when you're figuring out which units
11 to commit?
12 MR. MONTALVO: When we do our commitment process,
13 we do make sure we have sufficient resources to meet all our
14 ancillary services and the recall are regulation requirement
15 ranges from up to about 150 megawatts per hour. It's not a
16 very big hour in the first instance. But in the rear event
17 that you've expected that you would not have sufficient
18 resources available in real time to meet the regulation
19 requirements that is committed online with regulating range
20 available. Then an additional resource might be committed
21 in the day ahead to ensure that will happen, that gets the
22 price through.
23 MR. MEAD: Let me think about this. Thanks.
24 MR. MONTALVO: Moving on to the next topic, which
25 was changes to the reoffer period.

1 (Slide.)

2 This is really not the addition of a market, this
3 is a modification to the way offers are made into our real
4 time market. Right now, our current design allows resources
5 that did not clear at all into the day ahead, to reoffer
6 their are incremental energy flux for consideration in real
7 time.

8 The change that we have proposed and that NEPOOL
9 participants have endorsed, is allowing all resources,
10 whether or not they cleared the day ahead, to reoffer their
11 energy blocks for use in real time.

12 What this means is, the day ahead offers will be
13 used to commit the system and clear the day ahead market.
14 Then resources, to the extent they have better information
15 about their expected opportunities, fuel costs etcetera, in
16 real time, can make reoffers of their energy bid blocks for
17 use for real time dispatch, and so the system will be
18 dispatch then based on the basis of the real time offers.

19 The purposes of this is to improve the
20 information to the market available at each stage as we move
21 in time. It is the opinion of the ISO, our market monitor,
22 our independent market assessor, that this is a change that
23 would improve the overall efficiency of our day ahead
24 market.

25 MR. STINNEFORD: Tim Peet from MMWEC wanted to

1 offer his remarks and support for the variance of this
2 particular change.
3 MR. PEET: Good afternoon. My name is Tim Peet,
4 Senior Project Manager for the Massachusetts Municipal
5 Wholesale Electric Company. I just wanted to give our views
6 on this change that were posed and t he enhancement that's
7 being proposed for part of the project.
8 If you have been around long enough and gone back
9 far enough, the original settlement systems that we had in
10 New England, the New England Automated billing system, NABS,
11 throughout the OMO process, we were allowed, the generating
12 resources were allowed to submit two daily fuel prices to
13 the ISO and to NABS.
14 This was to allow the old fuel units to be able
15 to have their resources correctly priced and you would just
16 let the operators know which fuel you were on.
17 When we moved into the new market, we lost the
18 ability to specify a second alternate fuel but we gained the
19 ability to change our pricing on an hourly basis.
20 So I can give one price for one fuel during one
21 part of the day and then I can price my unit on its
22 alternate fuel for the second half of the day. With the
23 advent of SMG generators lost that prior ability. We were
24 only allowed to give one price and to clear the day ahead
25 market, you were not allowed to change any of the prices,

1 whether or not we had the proper fuel that was determined in
2 the real time settlement.
3 So one aspect of this reoffer period would allow
4 duel fuel units to offer in their second price as part of
5 the reoffer period at the end of the day.
6 As Marc said, all the resources will be eligible
7 to enter in the reoffer of their prices and price quantity
8 pairs for the day. If you clear the day ahead, that's all
9 you are going to be allowed to change.
10 Subject to mitigation, the real time dispatch and
11 market settlement will be based on those incremental offers
12 that were submitted during their reoffer period. Only
13 incremental energy offered price pairs will be allowed to be
14 changed.
15 So, under the standard market design, we have to
16 give one price and one quantity pair over the entire 24
17 hours. During the reoffer period, we will be allowed to
18 change that whether we clear the day ahead market or not.
19 Under SMD duel fuel units, as I said earlier,
20 lost the ability to have both fuels recognized into the real
21 time market. If you cleared on natural gas during the day
22 ahead, you are not allowed to go back and put in an oil
23 price and you had to live by those prices whether the ISO
24 dispatched you longer than what your day ahead commitment
25 was or not and whether you can get the fuel or not.

1 Most duel fuel units couldn't take the unit out
2 of service because of the lack of fuel because they had an
3 alternate fuel they could supply to be on line at the ISO's
4 request.
5 (Slide.)
6 So the features of that reoffer period, is day
7 ahead resources. Again, this is important. Day ahead
8 resource commitment will not be affected by these
9 resubmitted offers. So if you clear the day ahead, those
10 day ahead obligations will follow you into the real time
11 market.
12 Day ahead obligations must be satisfied by either
13 actually generating or buying from the real time markets,
14 just as we do today. There is no change in that market.
15 Net commitment period compensation would be
16 modified to remove all day ahead components from the real
17 time calculation. The day ahead operating reserve credits
18 would stay with the day ahead and real time would move into
19 the real time market. There would be a separation between
20 those two markets.
21 This is a simple software change. I believe it's
22 the setting of a flag in the user interface, and there is
23 some software that's associated with that commitment period
24 compensation that will allow the generating resources
25 greater flexibility in specifying pricing, and can be easily

1 undone if market issues dictate.
2 (Slide.)
3 However, with this rule change, we have two
4 concerns. The first concern is that there is a likelihood
5 that resources that do resubmit offers during the reoffer
6 period on a higher cost more available secondary fuel, will
7 basically price themselves out of the market in the real
8 time dispatch. Since the ISO will honor the commitment and
9 you choose to be dispatched online, they most likely will be
10 dispatched at their EcoMin, or economic minimum operating
11 level.
12 Under our rules in New England and SMD, those
13 resources cannot set price. Under this reoffer period
14 change, that rule become much more critical to a unit
15 sending down an EcoMin because owners price come out of the
16 market in real time would continue to be unable to set
17 clearing prices and my second concern is that duel fuel
18 units that do submit a second pricing into the market for
19 the higher cost secondary fuel.
20 Because they are only allowed to put in one price
21 in the 24 hour period, if they clear in the day ahead on the
22 gas price for a six-hour block, for instance and then they
23 come into the reoffer period, and then they submit a higher
24 oil price, they have to put it in for the entire 24 hours.
25 When the real time comes, the resources will most

1 likely have to submit a self-schedule to honor that day
2 ahead commitment. And by doing so, would be putting a zero
3 price for the hours that they did clear the at and reduce
4 the real time prices further than what they are right now.
5 So you increase the self-scheduling and you potentially see
6 them anyway.
7 So this is a big enhancement for the price of
8 these resources and we believe it's a good step and what we
9 should have done long ago. Thank you.
10 MR. MEAD: Just so I understand. What you're
11 talking about is the price bid that's submitted for a
12 resource submits a bid in the day ahead market. Some of the
13 its offer is accepted and that's what I presume that's
14 financially binding and the part of those energy that was
15 not accepted in the day ahead market, you can now submit a
16 different price bid compared to what was offered in the day
17 ahead market.
18 MR. PEET: If you want to think about it. Let's
19 make it simple. I have a 100 megawatt unit t hat has a
20 simple block. I bid in $50 per megawatt hour into the day
21 ahead market for the entire output of the unit.
22 If it clears one hour or more, at 4:00 o'clock,
23 when the day ahead schedules get published, if I clear for
24 one hour or more, I'm precluded right now from going into
25 the settlement new market software and making any changes to

1 any bid parameters. I'm locked out.
2 If I don't clear the day ahead, I'm free to go in
3 there and reoffer anything I want. Whether it's minimum run
4 times, minimum down times, start, stop, including my price
5 quantity pairs. To the extent that I have some gas, offer
6 the unit on gas on the day ahead and I don't clear, I can
7 put in an oil price and I can offer that fuel price on a
8 reoffer period and sit back and sell off my gas and not have
9 to worry about that. If I clear one hour, I'm not allowed
10 into the software.
11 Under this change during the reoffer period, they
12 are going to allow you to go in and just change your price
13 quantity pairs. You have to do that for the entire 24
14 hours. It's not like I clear one hour and I can put another
15 price for the 23 hours. I have to put one price in for the
16 full 24 hours. Then the operating day comes.
17 MR. MEAD: Let me just stop you. I thought the
18 premise of the example was that you are exempted for one
19 hour in the day ahead market. So now, I don't understand
20 the notion of being allowed to change the price for the one
21 hour that was accepted, unless you're referring to basically
22 a debt bid.
23 MR. PEET: They are somewhat similar. When an
24 offer comes in, I have to put in.
25 MR. MONTALVO: So everyone is clear, what we are

1 suggesting is, at the time of the reoffer period, all of the
2 incremental energy offers, that is all of the energy bid
3 blocks, the entirety of the resource, cleared, not cleared,
4 can be reoffered as those offers that will be used to
5 dispatch the resources in the day ahead -- excuse me, and
6 real time.
7 MR. MEAD: And to the extent that the one hour
8 that was accepted in the day ahead market is now, I guess,
9 if it's continued to be accepted, then I presume that the
10 unit gets the day ahead price. And if it's rejected it gets
11 the real time price and it would be rejected or bought back
12 based on this reoffered real time price.
13 MR. MONTALVO: Right. As Tim says, and I think
14 it's important. This is an important feature. It's the day
15 ahead schedules and so it's financial binding. You're still
16 financially bound to whatever clears through the day ahead
17 market for that one hour at that price, you know.
18 If because of changes to your offers in the
19 reoffer period, you do not sell as much power into the
20 market in real time, you still have to buy it back.
21 MR. MEAD: Thanks.
22 MR. PEET: That's all.
23 MR. MONTALVO: Are there any other questions on
24 this?
25 CHAIRMAN WOOD: The first two items, wasn't there

1 a kind of lingering concern from you, David on the first
2 item? Just so they can take away something, a clear
3 message.
4 MR. MEAD: I still need to think further about
5 this issue that Peter raised about whether their regulation
6 price ought to reflect the sum of the offer price as well as
7 the estimated opportunity cost. I needed to understand
8 that.
9 Also, the notion of whether this makes sense not
10 to consider your regulation procurement in the day ahead
11 market at the time that you're procuring the rest or when
12 you're committing all the rest of your resources. Those are
13 the two.
14 CHAIRMAN WOOD: Reoffer?
15 MR. MEAD: I think, based on what I've heard,
16 this seems to make sense to me. And my clarifying questions
17 clarify the issues or your answers have.
18 CHAIRMAN WOOD: Anything else on this one?
19 MR. MEAD: I've been fed another question.
20 (Laughter.)
21 MR. MEAD: What does it mean subject to
22 mitigation and how would this work?
23 MR. MONTALVO: Right now, all the offers that are
24 made into the market are subject to the scrutiny of our
25 market monitor. So any price changes that are offered under

1 the offer period would still be subject to the scrutiny of
2 our monitor.
3 Whatever mitigation is appropriate by them under
4 our mitigation rules, the mitigation rules that they've
5 developed will apply here. That's all that means.
6 MR. MEAD: Thanks.
7 (Slide.)
8 MR. MONTALVO: The next component of the phase
9 one of ASM is a change to -- it's really a software change,
10 to allow external dispatchable transactions to set price.
11 What the change will allow is for external
12 dispatchable transactions, scheduled into the hour to be
13 evaluated ex ante each five-minute dispatch cycle. To the
14 extent the transaction is marginal in that dispatch
15 execution, it will set price. That's the nut of it.
16 MR. STINNEFORD: Bob.
17 MR. STEIN: Before I give the long and detailed
18 explanation of this, I understand when I was out of the room
19 on a conference call, several things were attributable to
20 me.
21 (Laughter.)
22 MR. STEIN: I want to make it clear that if they
23 were insightful, then they are correct attributions. If
24 they were lame attempts to be humorous or sarcastic, they
25 are also accurate.

1 (Laughter.)
2 (Slide.)
3 MR. STEIN: I guess I asked to talk about this.
4 My client is Hydro Quebec and we sell into the marketplace.
5 Oddly enough, this change doesn't affect what Hydro Quebec
6 paid, it affects how the rest of the market sees the
7 contract, which is external as Marc correctly said.
8 Under the current rules, Hydro Quebec will be
9 selling in at $500 a megawatt hour in external contract and
10 if the highest resource running in the energy market is
11 $200, the marginal price in New England will be $200.
12 We've had several instances in the past where
13 units in New England would back down because of a shortage
14 of reserves because you can't provide reserves externally.
15 Energy came in at a higher price. The odd effect was that
16 during a critical period of shortage of r reserves, the
17 energy price went down because we were backing units down in
18 the energy market. This corrected.
19 I won't pretend to explain. I think everyone
20 needs to understand exactly how we're making the software
21 change. Basically what is happening here is we are
22 eliminating a seam.
23 This is allowing resources who are outside of the
24 New England control areas set price in the same way,
25 fundamentally the same way. I understand it's not exactly

1 the same, but fundamentally the same way that internal
2 resources do.
3 MR. MEAD: The external resources are dispatched
4 within a five-minute period? That's a question.
5 MR. MONTALVO: No. Only external transactions
6 are evaluated there. They said dispatchable transaction is
7 evaluated on an hour ahead basis. So essentially, the
8 evaluation software is a hour ahead, it makes the estimate
9 of what the LMP is going to be in that hour. To the extent
10 the transaction is considered to be in rate for that hour,
11 it will be scheduled and it is scheduled for the hour.
12 What the software change, what that is doing is
13 execution. It will look at the transaction in each five-
14 minute execution and will examine it by the five-minute and
15 say, are you marginal now? As resources are being used, if
16 it is, it will set the price.
17 MR. STEIN: So the contract stated there for the
18 hour will move theoretically in and out of setting the
19 market price.
20 MR. MEAD: If the external resource really was
21 dispatchable and you really needed it, it would have set the
22 price. And if you didn't need it, because demand went down,
23 for example, then it's not really marginal. And at that
24 point, it doesn't set the price.
25 MR. STEIN: It doesn't set the price but it gets

1 paid and, of course, the whole rationale -- and believe me
2 we'd like to see better dispatch or faster dispatch. A
3 logical question is, why don't we have five-minute stretch
4 of external resources?
5 There are technical issues on both sides of the
6 border that make it difficult. All of the border. It's not
7 just the border of Quebec. But the ISO's basic operating
8 assumption, as I understand it, and Marc and others can
9 correct me, is they commit this hour-long resource after
10 evaluating and coming to the conclusion that it's worth
11 having there for the hour.
12 MR. MEAD: Thank you.
13 MR. IDE: I would just point out for your
14 benefit. In terms of the stakeholder process, these three
15 changes that we've just discussed, the regulation market,
16 the reoffer period, and the external transaction price
17 setting, in fact are going to be dealt with by the equal
18 participants committee a week from today, and the marketable
19 changes that would implement those would be filed with you
20 shortly thereafter. These are well through or almost
21 through the stakeholder process.
22 MR. STEIN: Chuck, didn't these all pass by
23 unanimous or virtually unanimous margins?
24 MR. IDE: Near unanimous. There is a very high
25 level of support for both of the pieces of it.

1 CHAIRMAN WOOD: On this last one, external, is
2 that generally the HQ tie or are there some from New York?
3 MR. STEIN: Only Brunswick.
4 MR. MONTALVO: So that is phase one.
5 CHAIRMAN WOOD: The three items will be submitted
6 in October?
7 MR. MONTALVO: Yes and probably in about three or
8 four weeks time.
9 CHAIRMAN WOOD: And to keep you guys on tract,
10 you would need a response from the Commission by?
11 MR. MONTALVO: In your 60-day timeframe.
12 CHAIRMAN WOOD: All right.
13 MR. MONTALVO: The next elements are phase two
14 elements.
15 (Slide.)
16 CHAIRMAN WOOD: Which will be next tune, right?
17 MR. MONTALVO: No, earlier than next June.
18 (Laughter.)
19 MR. STEIN: Not next June, next, next, next June.
20 COMMISSIONER BROWNELL: That's the anniversary.
21 I'm going to be watching.
22 MR. MONTALVO: No earlier than June 2006 is the
23 implementation date for these elements. These were elements
24 that in the fall, when we were working on the design really
25 participants needed more information in order to make an

1 informed decision as to whether or not these design elements
2 were the right way to go.
3 And if implemented, would provide the right price
4 signals for various products and services that they
5 ostensibly will be designed to provide in the marketplace.
6 So, rather than going around in circles and come
7 up with nothing, what we decided to do in concert with our
8 participants is, take a step back, take a deep breath and
9 say, okay. What do we need to know in order to make well
10 informed decision as to whether or not these are the right
11 market designs?
12 So the elements that I'm going to be talking
13 about here are work in progress. The nature of the
14 presentation is a description of the ISO's proposal, as made
15 thus far, and we are going to be preparing a series of
16 analyses, white papers and studies over the coming couple of
17 months, in order to make sure that our participants have, to
18 the best extent we are able, the information they have to
19 come to an informed decision about them, so we can move from
20 the conceptual phase into the design phase and get something
21 filed with you guys in the September timeframe of this year.
22 (Slide.)
23 The first two elements include the changes to our
24 reserve markets. This has two components broadly speaking.
25 The first component is the addition of a locational

1 component to our already existing forward reserve market.
2 The second part -- all right that's better. The
3 second part is the real time joint optimization of energy
4 and reserves. The other component is the addition of the
5 asset related demand. There are some other small changes
6 that we anticipate making, such as allowing the offering of
7 medical response rates and things of this type, which are
8 really secondary issues and we don't need to spend any time
9 with those things today. They're small.
10 (Slide.)
11 I probably doomed myself here by saying they were
12 small. In the reserve market changes, we had a design
13 choice to make. Some work was done inside the ISO in
14 consultation with our consultants last year, to decide what
15 was the right way to implement reserve markets.
16 We already had a forward reserves market, and the
17 reasons for going with the forward reserves market was the
18 recognition that we needed additional infrastructure that is
19 fast start capable resources to provide a 30-minute response
20 in some of our import constraint areas.
21 We really needed a capacity type product that
22 really targeted certain types of resources, right. So that
23 was one of the reasons for going with the forward reserve
24 market.
25 When thinking about how to enhance that, how to

1 add additional reserve products and make them locational,
2 analysis was done as to whether it was better to make our
3 existing forward reserve market locational and add a real
4 time pricing component or to go to a day ahead real time
5 reserve market design.
6 And then there was questions as to whether or not
7 they made sense to use a multi-settlement design where the
8 day ahead would settle against real time or your forward
9 market would settle against real time or whether they should
10 be separate markets.
11 So these are some of the things we talked about
12 and debated. Ultimately, we decided that the way to go is
13 to add a locational component to our forward reserve market
14 and go to real time pricing reserves. And that these
15 markets would be separate markets, that is the forward
16 market would not settle against the real time market.
17 The reason for having a locational component is
18 that we today have import constrain area where we have to
19 operate resources daily RMR resources. That is commit them
20 out of merit in order to protect against unforeseen
21 contingencies.
22 The big reason for having to deal with that is
23 infrastructure inadequacy actually. We do not have the
24 optimum mix of generating resources and transmission
25 resources in order to protect against these second

1 contingencies without running resources out of merit.
2 But we want to get those resources. We are going
3 to then add this 30-minute local requirement, which will
4 allow us to then price the value of that type of resource in
5 those locations.
6 In real time, resources that are used in real
7 time to provide reserves will also be compensated. And so,
8 in real time, we'll look at the resources that have been
9 committed into real time and we'll look at, as part of our
10 dispatch algorithm, the real time reserve requirements. A
11 30-minute reserve requirement, 10 minute non-spinning and 10
12 minute spinning requirement will be incorporated as
13 constraints into our real time dispatch algorithm.
14 The system will be dispatched that way, and to
15 the extent those constraints are binding and we're unable to
16 meet our requirements in real time, we'll have prices for
17 those real time products.
18 (Slide.)
19 What I've just described is really the broad
20 outline of what we've decided to do as far as reserve
21 systems. We discussed this design with the markets
22 committee for a large part of last year. The agreement that
23 we came to with the participants is as follows: we are
24 planning to do the right thing. That is our reserve markets
25 should provide signals that encourage efficiency provision

1 of the system and locational operating reserve so there is
2 broad agreement that locational support is required and
3 we're talking about this both the investment in and real
4 time allocation of those resources.
5 And then, it was decided also that the forward
6 reserve market with real time reserve pricing should be
7 pursued to advance the region toward the objective. That is
8 the proposal that we've made which broadly has these
9 elements, seems a reasonable way to go. That's where we are
10 proceeding from right now.
11 MR. STINNEFORD: Just to point out that with
12 respect to what the participating stakeholders have agreed
13 to in the design basis document with respect to phase two of
14 the project, this is about where we are right now.
15 The level of detail that Marc is going to get
16 into beyond here really reflects where the ISO is coming
17 from. With respect to this element of the ancillary service
18 market that has not yet been fully met and supported by the
19 stakeholders, this is where the Committee is at this point.
20 CHAIRMAN WOOD: Where is New York and PJM on this
21 type of issue? Have they grappled with that yet?
22 MR. MONTALVO: New York has a day ahead and real
23 time reserve market design which they put in as their SMD2
24 and PJM is working on its RPM model and you know, I'm not
25 quite sure where that stands right now. There is different

1 approaches.
2 One of the reasons I think why we think it's very
3 important to go with the forward reserve approach as opposed
4 to just a daily approach, is that we want to have price
5 signals that induce investment in very many capable
6 resources in our import constraint locations.
7 In order to get investment grade price signals,
8 we really needed to have a market that's of sufficiently
9 long procurement periods that allow prices to reflect at a
10 minimum. Things like going forward costs and perhaps
11 investment costs, the closer you get to real time, those
12 values all tend toward zero. So what you get is just a
13 variable cost of operating those resources.
14 So that won't in our estimation get us to where
15 we need to be. David you look like you have a question.
16 (Laugher.)
17 MR. MEAD: I have a couple of questions but I'll
18 ask them after you've finished your discussion on the
19 forward reserves.
20 MR. MONTALVO: That's fine.
21 (Slide.)
22 This chart here or this table provides a summary
23 level of the changes to the existing forward reserve market
24 that we're proposing here. The existing market purchases
25 are system requires, are offline system requirements. For

1 the NEPOOL control area, we maintain 10 minute non-spinning
2 and 30 minute non-spinning requirements. That's what's
3 purchased in our current forward reserve market. What we
4 intend to do is add the locational aspect of that, which
5 would be the locational 30 minute requirements.
6 Our existing market is asset specific. That is
7 specific resources submit offers to provide reserves. What
8 we are proposing is to make them portfolio based in order to
9 provide some more flexibility to the supplier, to allow them
10 to better manage their risks as far as performance is
11 concerned.
12 And what a portfolio offering would look like is
13 essentially a megawatt quantity of the type of reserve.
14 Either 10 minute non-spinning or 30 minute non-spinning in a
15 location for a price. Then the actual set of resources used
16 to meet that obligation will be designated by the provider
17 into the day ahead market and then will be cleared through.
18 Right now, we only procure our system
19 requirements on an on-peak basis. So divide by 16 on peak
20 requirements. But we do have system requirements 24 hours a
21 day and so what we are going to do is also buy in our off-
22 peak requirements and currently only generators can
23 participate.
24 With the introduction of the asset related demand
25 infrastructure, demand resources will now be able to

1 directly participate in our reserve markets. Hopefully,
2 that will provide additional competition for the market.
3 MR. PETERSON: Can I interject a comment here?
4 I'm not sure how we are going to integrate the issues about
5 demand side resources but this slides start to get into the
6 area that first of all is going to be discussed next week
7 into the Markets Committee.
8 Where the slide says includes demand side
9 participation, it includes only what I would call a small
10 slice of available demand side resources, which I think is
11 asset related demands. The demand side resources that have
12 tele-metering that have rings like a generator, they're
13 generally large. A lot of them are behind the meter
14 generation. They look a lot like a generation resource.
15 What Marc is discussing is an issue in load pockets of how
16 to get additional resources to deal with locational
17 problems.
18 There are a number of people who feel the ISO is
19 not looking aggressively enough at all the other demand
20 resources that might be available there because they're not
21 eligible to participate. Because they don't look like a
22 generator, they can't be ramped up and down. They may be if
23 someone can cut off it's production line or reduce its air
24 conditioning during the summer peak or do something else
25 that would contribute as a resource in that load pocket.

1 But, the ISO is saying we're not even going to
2 look at those until sometime after 2006, probably 2007
3 before we're going to figure out a way to try and integrate
4 those resources.
5 People have asked for further discussion next
6 week at the Markets Committee, whether or not the ISO can
7 broaden the scope of resources it's looking for. I think
8 that's one of the issues we want to raise in terms of fully
9 evaluating the available resources that are currently
10 actually in demand side programs at ISO New England but will
11 not qualify for this newly designed reserve market.
12 MR. MONTALVO: I think there are a couple of
13 things going on. First of all, the reserves we seek to
14 procure, whether they are from a supply resource or a demand
15 resource, have to meet the technical criteria laid out in
16 our operating criteria. And also, the NPCC and their
17 operating criteria for the provision of continuous spin
18 reserves.
19 Right now, there is a technical set of criteria.
20 So what we have sought to do with our asset related demand
21 class and the participation in our reserve market, is to
22 allow any resource that meets those technical criteria to
23 participate.
24 I think I agree with Paul when he says what we
25 are describing is a narrow set of resources, because I think

1 at this time, the set of resources that can meet the
2 technical criteria for the provision of continuous spin
3 reserve from the demand side may be small.
4 But, we have also committed to doing some
5 internal research projects, internally in the ISO to
6 determine how the type of resources may meet the technical
7 criteria, even thought today they don't.
8 What kinds of alternative telemetry and command
9 and control might be sufficient to allow the provision of
10 the service. But we are talking about a reliability service
11 first and foremost here. We have decided to take a, let's
12 wade in and make sure that we're doing things that are
13 consistent with ensuring system security all the way.
14 We will research and study, and make sure to the
15 extent that we are confident that we can broaden the class
16 of resources and not in any way jeopardize the security of
17 the system, we'll do that.
18 (Slide.)
19 So the reserve areas that we're talking about,
20 where we are going to buy, our locational reserves, right
21 now we are defining them in terms of those areas which are
22 import constraint locations, defined by closed interface.
23 There are areas right now where we have fairly
24 regular daily RMR commitments in order to protect against
25 our second contingencies. Those areas today are Southwest

1 Connecticut, the entire state of Connecticut, and the NEMA
2 Boston areas.
3 (Slide.)
4 As I mentioned to you before, we also have this
5 real time reserve component also and there is a question as
6 to how the forward reserve market interact with the real
7 time. I think it's important to reserve that it is a
8 separate product.
9 Our forward reserve product are 10 minute and 30
10 minute non-spinning reserves and they have specific delivery
11 requirements. Any resource that offers in, who is cleared
12 in this market and offers in and designated something in the
13 day ahead to provide the resource, must provide energy above
14 our established threshold price and is also subject to
15 performance penalties.
16 That is, if they fail to reserve sufficient
17 resources to meet their obligation day ahead, there is a
18 penalty. If in real time they fail to reserve the resources
19 they designate in day ahead become unavailable, there is a
20 penalty.
21 And if they've reserved all the resources
22 properly but when they are dispatched they are activated
23 because either they are in-rate or they are with the
24 contingency and they fail to activate, there is a penalty.
25 And the penalties are especially designed to ensure

1 performance. They are liquidated-type damages penalties
2 where for resource providing reserves in real time are at
3 real time dispatch. Resources that are available will be
4 used for the purpose. But if they fail to activate, if they
5 don't respond, if they fail to activate in particular, there
6 are no penalties. They've lost opportunity to earn energy
7 revenues.
8 So they are a different product and the
9 opportunities and the risks associated with the provision of
10 one resource versus another are different. That is the
11 primary reason of why we don't have the forward reserve
12 market settle against the real time reserve market. We
13 would be settling apples and oranges.
14 MR. MEAD: Can I stop you there for a second.
15 Why have you decided not to impose a resource that's
16 scheduled in real time to provide reserves then you call
17 upon it and it fails to provide energy. Why isn't the same
18 penalty for failing to provide energy assessed against that
19 resource compared to a resource that was procured for
20 reserves in the forward market?
21 MR. MONTALVO: Let me be frank. We could do
22 that. But our proposal, as we have come up with it, has
23 decided that we didn't want to -- we don't have an
24 availability payment associated with a provision of real
25 time reserves. There is no offer into the reserves market

1 in real time. So with any resource that's offered into real
2 time for the provision of energy, therefore it's available
3 for the provision of reserves in real time.
4 MR. MEAD: Are reserves procured in real time
5 paid any availability price?
6 MR. MONTALVO: No they're not. There is no
7 availability payment.
8 MR. MEAD: So if they happen to be there that's
9 great and if they're not they just really sort of a free
10 resource for you.
11 MR. MONTALVO: Yes. If they were a shortage over
12 here its in real time. Under our system here, the resources
13 will be compensated. The shortage prices the resource
14 provided reserves, otherwise there is no explicit
15 compensation if there is no reserves in real time.
16 MR. MEAD: In that case, where the reserves in
17 real time are paid a price, why aren't they assessed the
18 same penalty that a forward reserve resource would be
19 assessed if it fails to provide energy? Presumably they're
20 both there for the same reasons. You've procured some
21 resources in the forward market.
22 MR. MONTALVO: I think there are a couple of
23 things. First of all, the forward reserve resources were
24 not procuring spinning reserves on a forward basis. The
25 principal resources you're speaking of is procured in real

1 time with a spinning reserve component.
2 If we set up, conceptually one could set up a
3 contractual arrangement, I suppose, where you would offer in
4 and there would be performance penalties associated with a
5 failure to provide in real time a spinning reserve that you
6 sold either hour ahead, day ahead, whatever it is.
7 So this issue that you've brought up is actually
8 an issue that several of our participants have also raised
9 and one of the issues that we are going to be working
10 through with our participants over the coming couple of
11 months, as to whether or not such an approach would be
12 appropriate would have benefits and how that would compare
13 to what we have proposed.
14 Since this is an issue that we're working on, I
15 don't have any ready answers for you because I think this is
16 an issue that's under investigation.
17 MR. MEAD: For myself, I don't know whether
18 penalties are the right thing or not, but I'm a little
19 perplexed that penalties are assessed for forward reserves
20 but not real time reserves. That there is this different
21 treatment of forward and there is this different treatment.
22 MR. MONTALVO: Sure. That takes us to slide 27, I
23 think.
24 (Slide.)
25 This actually allows us to segway pretty nicely

1 into some of the design issues that NEPOOL has asked us to
2 address. So for example, regarding a forward reserve
3 market, how exactly are we going to determine the location
4 requirements. What is that methodology precisely? How are
5 we going to allocate the costs of procuring these reserves
6 for the loads in each location? How would that be done?
7 We have proposed approaches, but we really were
8 never able to come to a consensus position or I think really
9 a common understanding of whether they made sense or not.
10 We are going to spend some time working through
11 our rational with the participants to make sure everybody at
12 least understands where we are coming from and perhaps we'll
13 end up some place else.
14 CHAIRMAN WOOD: Is your initial approach, that
15 was confirmed on an earlier slide Marc, about slide 23, is
16 the answer to that, that the ISO proposes that it be a
17 systemwide upward allocation because it's system benefiting
18 activities going on or is it more allocated?
19 MR. MONTALVO: You're speaking to the cost
20 allocation issue?
21 CHAIRMAN WOOD: Correct.
22 MR. MONTALVO: What we were thinking is this.
23 Given the distribution of resources that can provide
24 reserves inside the New England area, there is a probability
25 that much of the reserves could be carried and actually our

1 forward reserves would be procured from resources physically
2 located inside of our import constraint areas. Not all, but
3 a good percentage.
4 But much of that reserve would also be supporting
5 the system reserve requirement, in our estimation it would
6 be inappropriate to charge the loads in Boston and
7 Connecticut for all of the system reserves or the load
8 weighted sure of the system reserves and the local reserves
9 from those systems, just because they're physically located
10 there.
11 Rather, the scheme that we are trying to develop
12 would allow us to allocate to those areas, the cost
13 associated with basically the incremental reserve
14 requirement imposed by the constraints in that area.
15 CHAIRMAN WOOD: What is the cost that is being
16 borne today that is analogous to this proposed cost?
17 MR. MONTALVO: On a systemwide basis, the system
18 reserves which are allocated out to load networkwide and
19 then on a locational basis that would be the daily RMR
20 costs, which are allocated to on a zonal basis.
21 So essentially, what we would want to do is come
22 up with an allocation scheme that approximates that as best
23 as possible. And it's not so neatly straightforward when
24 you have a single resource that will be providing
25 simultaneously local reserves and spinning reserves. There

1 has to be a way to allocate those costs out.
2 CHAIRMAN WOOD: I think we're going to have some
3 panel responses to this. Let me just figure out process
4 wise where we are. Are you going to speak a little bit more
5 market and we're going to have the panel respond?
6 MR. MONTALVO: Yes, I just want to take two more
7 minutes and go through these.
8 (Slide.)
9 Both for these issues in question, this is not an
10 exhaustive list by any stretch but these are some of the
11 issues that I think are going to require a fair amount of
12 work on our part.
13 There are a lot of questions about how t he LICAP
14 market and the local forward reserve market will interact
15 with each other. A bunch of different things. What will
16 happen? And what is the ISO's principles as regards to
17 market recognition.
18 So how can these markets, when all is said and
19 done, fit together such that the total revenues that are
20 collect make sense and the revenue streams going to any
21 provider of all three types of service, also make sense.
22 So we'll have some work to do there. There is
23 also been a lot of talk about offer caps price mitigation
24 and these kinds of things for our forward reserve market.
25 How will they be established and the methodology and this

1 type of thing.
2 So those are some of the issues that we w ill be
3 wrestling with over the next month or so. I think this is a
4 good break point and we can go the participants. Did you
5 want to say anything?
6 MR. IDE: Mr. Chairman, I think you've got a
7 combination of both prepared remarks and some impromptu
8 reactions to what was just said. So I think prepared
9 remarks are Peter, you're going to start. There is a
10 challenge for you Jeff.
11 (Slide.)
12 MR. FULLER: Thank you. I was selected I guess,
13 to kick this off to provide some overall context and in
14 large measure tell you what's right here. I'm going to have
15 to profess that by saying I've got sort of that glass half
16 full, glass half empty set of remark because there is a lot
17 right here but we are not done by any stretch.
18 What I'd like to talk about is, the first major
19 bullet up there is, at least from one perspective, and I
20 think it's actually fair common. What the design, what the
21 reserve market ought to do or a set of reserve markets ought
22 to do. Then talk a little bit about what the current
23 proposal is doing. Those work and then some of the key
24 issues that are still outstanding.
25 And that in fact really implicate some of the

1 design choices Marc just talked about and others. The key
2 issues in the reserve markets, first of all, I think one of
3 the references that was made earlier was to the New York
4 model, which actually has the day ahead co-optimized reserve
5 market reserve and energy and real time, which is a new
6 aspect as I understand it.
7 That's a different road to go down, or perhaps
8 another step in our evolution down the road. From the
9 supplier point of view, we think that makes an awful lot of
10 sense to continue exploring that as opposed to the forward
11 reserves that we've got here.
12 But the road we're on right now is a forward
13 reserve market with real time pricing and that's what I'm
14 going to try to talk about.
15 What we think the market ought to do is recognize
16 that when you start running out of things, out of reserves,
17 reserves and energy really have equivalent values. That's
18 an element the ISO has clearly recognized and built into the
19 work they've been doing for some time and is built into this
20 proposal. That's a very positive aspect.
21 Products and price. We've got the three
22 categories of product, the spinning reserve and then 10
23 minute non-spin and the 30 minute. The quantities cascade
24 and the prices cascade so we're never paying more for these
25 "low" quality 30 minute reserves than you are for the

1 spinning reserves. Again, sort of basic market pricing
2 outcomes that make sense. Again something the ISO has
3 caught onto, understands, and it's built into our existing
4 arrangements. And it's built in going forward. A very
5 positive issue.
6 Where I think we are a little short, the reserve
7 service, and I think this gets to your question David a
8 little bit. Reserves service, it has value even when you
9 are not short of it. That's an element that we have not
10 fully captured yet. In the forward reserve market, the way
11 that works, you take an obligation well ahead of time and
12 get paid essentially in little pieces as the time unfolds.
13 That effectively pays you right now for that little piece of
14 reserve you are providing in this hour and so forth. That
15 makes some sense.
16 The concern that's still out there is that in the
17 real time reserve markets, we do not have an availability
18 offer. It is as you put it, essentially a fuel resource,
19 free system to use. By offering energy, you are also
20 providing reserves and I think there is a real need to
21 continue to evaluate that question, whether there is a
22 better way to do it.
23 The underlying issue, one that's been in several
24 of the ISO slides today, the question is, how far along we
25 have come in actually capturing this, is that market pricing

1 must reflect operational decisions. This has been a
2 principle that I've espoused many, many times. We are not
3 here as market participants to second guess or to tie the
4 hands of Steve Whitley's organization in operating the power
5 system and in maintaining reliability. That has absolutely
6 got to be something that they have free reign to do.
7 The question comes up in when the decision is
8 made to start a power plant in a constraint area for second
9 contingency resources to start a quick start unit and run it
10 at its minimum block because we think a transmission line is
11 about to trip. Whatever the decision is.
12 That has to come through with price and we have a
13 long way to go in that regard and specifically in the
14 reserves market, I think the biggest concern that I see and
15 I think Joel Gordon will be speaking to it more is Marc
16 mentioned in these constraint areas, we have a lot of daily
17 RMR, which is essentially decisions made in the day ahead
18 timeframe, not necessarily within the day ahead market but
19 decisions made Tuesday or Wednesday, and so forth, that
20 create energy price impacts downward and create reserves but
21 are not captured in any sort of a market price.
22 That is an ongoing problem that this mechanism
23 has yet to deal with. In fact, that's where the glass half
24 empty largely comes in.
25 Moving further down, I think again, reinforcing

1 some of the things Marc brought up. The portfolio approach
2 with the bilateral trading mechanism. That's a positive
3 step that adds flexibility, it adds liquidity and that's
4 going to be good for the market, for consumers.
5 Demand participation and I will let the demand
6 folks speak more to that. But certainly as an objective and
7 as an incremental step, that's a positive. Again, putting
8 in more options in the market.
9 The scarcity pricing in real time, when we do run
10 out, there different things kick in in terms of pricing and
11 I think the proposal that's on the table from the ISO is a
12 substantial step ahead of where we are today with the
13 scarcity of shortage pricing that we have. So again, a very
14 positive move in this regard. And the sense that the
15 forward reserve market that we have adopted as part of the
16 design basis document, includes both locational requirements
17 as well as respecting the system requirements. Again,
18 positive movement that what we really have is locational
19 markets, we really need to reflect that. So again, positive
20 movement.
21 What I guess I'd like to leave as my final
22 thought is. Those are positives, they are good moves, they
23 are incremental advancements in the market and that's why I
24 think the design basis document has the broad support that
25 it has. But we need to keep our eyes focused on where we go

1 next. Is there any room for availability offers in real
2 time and potentially in day ahead? How do we capture those
3 day ahead reserve incremental decisions? Is it through a
4 day ahead market as discussed or is there some other
5 mechanism?
6 And the other one that I really didn't talk about
7 but highlight here, is something that has been a theme
8 throughout our experience with the forward reserve market is
9 that, there is potentially a disconnect between the parties
10 that take on the obligations in the forward reserve market
11 and are paid for it, and the parties that actually provide
12 the real time reserves that are counted on in the system.
13 So there is a decoupling that is, I believe still
14 exist under this new proposal and again, it's something that
15 bears further scrutiny as we move ahead.
16 CHAIRMAN WOOD: I know your company operates in
17 both the New York market and this market. Is this a
18 regional difference that can be handled or is there a
19 problem or future seams issue that this is dealt with
20 different in New York than it is here. If so, is it major
21 or minor, or in between?
22 MR. FULLER: I don't know that it's a seams issue
23 in sort of the classis sense that it inhibits trade between
24 the two regions or anything like that. It is a difference
25 and our sense is that the day ahead full optimization is a

1 good answer, it's a good outcome. So we prefer the New York
2 model. I'm not sure being different is a seam. Although in
3 one sense it certainly is.
4 CHAIRMAN WOOD: Does it prevent a New York
5 generator from providing reserves in the New England market
6 and vise versa?
7 MR. FULLER: We can't do that in any event, as I
8 understand it. There is a fairly bright line at the board
9 that says, your reserves stay there and our reserves stay
10 here, other than the reserve sharing agreement.
11 CHAIRMAN WOOD: Right.
12 MR. FULLER: Virtual 200 or 300 megawatts of that
13 is sort of cooperative agreement as I understand it.
14 CHAIRMAN WOOD: Is that what we want to have
15 long-term up here?
16 MR. STEIN: We just touched on something that's
17 near and dear to Hydro Quebec's heart, and that is external
18 provision of reserves is not allowed now and that's
19 something we see as future enhancement.
20 CHAIRMAN WOOD: Reliability, is that a NERC rule?
21 MR. MONTALVO: Right now, MPCC and the ISOs are
22 working together to see what the technical requirements for
23 such an exchange of reserves be on the emergency reserves
24 sharing and provisions that exist today, what would those
25 things be. It's not a purely market issue.

1 MR. STEIN: There is no prohibition against it
2 per se but Marc is right. There has to be a lot of work to
3 make sure that people are comfortable with what you assume
4 is on the other side and would it be there when you need it.
5 I'm not sure Steve is a big fan of getting
6 reserves from hundreds of miles away but it can be done. We
7 do it from hundreds of miles within the region, but it's an
8 issue.
9 CHAIRMAN WOOD: Okay. Any more questions?
10 (No response.)
11 MR. IDE: I think Mr. Brennan was next.
12 MR. BRENNAN: Tim Brennan from National Grid USA.
13 (Slide.)
14 First, I'd like to thank Commissioner Judson of
15 the MASS DTE and Commissioner Brownell, Chairman Wood and
16 the FERC staff who were kind enough to join us today.
17 I think everyone else who is here shows this is
18 an important issue that we all need to pay attention to,
19 especially in the next few months as we develop the detailed
20 market rules.
21 What I've done on my slide is captured in the
22 three main bullets, kind of the objectives. Gordon had
23 these on one of his slides earlier. But the first one was
24 to provide price signals that encourage efficient provision
25 of system and locational operating reserves.

1 What I want to say is, that you must be very
2 careful in how you design this market. You must carefully
3 consider, number one, how this market will interact with the
4 supplemental overlap, complement require modification. I
5 was going to even put in possible replaced, but I'm sitting
6 between Peter and Joel.
7 (Laughter.)
8 MR. BRENNAN: Seriously, there is a lack of
9 academic consensus on the needed capacity market being need
10 instead of uncapped energy in the fully contracting of
11 reserves. We're hear talking about at least partly fully
12 contracting reserves, even on a locational basis.
13 So you have to be very careful on how these two
14 markets, if we are contracting on a locational basis
15 capacity, which will be reserves based on a benchmark
16 peaking unit, how does that interact with what you are
17 incenting on the forward reserve market contracting.
18 It's very important that we recognize that there
19 is some debate ongoing as to whether you need one or the
20 other or both. If we are going down the path of both, we
21 have to be very careful on how they interact to make sure
22 they're not overlapping or interfering with each market
23 locational ICAP and the locational forward reserve market.
24 Along those lines, proper choices must be made
25 for the type quantity and location of the reserve purchased

1 in this forward auction, including proper adjustments for
2 changes in the transmission system and the interfaces which
3 will change how many 30 minute reserves you might need the
4 contract for. The same with generation changes. Either
5 additions or retirements will affect the amount that you
6 might want to procure and each forward option. So you must
7 pay attention to that and mention the benchmark capacity.
8 What you want to use in each market. Are they the same? Are
9 they different, and other details, important details, other
10 the price setting mechanism and market monitoring.
11 So we must pay very careful attention to that,
12 and it's been mentioned a couple of times today that one of
13 the most important decisions which ties to how these markets
14 interact is, what is the proper adjustments for the revenues
15 between the locational ICAP market and the locational
16 forward reserve market.
17 That's something I know in my own mind I thought
18 for sure the was a clear, proper way and then reading some
19 of the expert testimony, in the ICAP case, if nothing else,
20 I think we should take that time and make sure we consider
21 this interaction and get that right.
22 Another goal is to improve the market pricing
23 during supplies shortage conditions and under this bullet, I
24 wanted to make the point that we must carefully consider and
25 justify the level of these reserves constraint penalty

1 factors because it's those reserve constraint penalty
2 factors that we choose for the 30 minute, 10 minute non-
3 spin, 10 minute spinning.
4 When we run short of those, these reserve
5 constraint penalty factors will kick in, not only to
6 determine the reserve pricing in real time during those
7 shortage hours, but also it will have a direct effect on the
8 energy clearing prices.
9 I have a bullet there that there is the potential
10 to double if we were to run out of all reserves, I probably
11 made a mistake and seem to indicate that all you have to do
12 is run out of 10 minute spinning reserve in that bullet.
13 But, if we were to run out of a 30 minute
14 reserve, 10 minute non-spin and 10 minute spinning reserves,
15 we would be up to an added and reserve constraint penalty
16 factor of $1,000, which would be added potentially as a
17 constraint to the locational marginal price in the energy
18 market.
19 So is it appropriate if we choose $1,000 for the
20 sum of those penalty factors to allow the energy price to
21 double at that point, up to $2,000 or even greater,
22 depending on congestion lost components. Maybe it is, but
23 let's think about it.
24 Let's have our economist justify the signal
25 that's used at that point. Let's not just pick numbers that

1 we perhaps don't need to go that high in total, but we need
2 to go a little higher when we run out of 30 minute reserves,
3 maybe that will help us with the 30 minute contingency
4 problems we're having. I don't know. There hasn't been any
5 discussion on that. That's something we should consider.
6 MR. MEAD: Do you have any suggestions for what
7 standard or what basis you would use for deciding what
8 energy price should be when we run out of reserves?
9 MR. BRENNAN: No. I think the problem is, we
10 haven't really had any discussion. It may be purely by
11 necessity, a subjective decision that we have to try and see
12 how it goes.
13 I can understand that you would want the reserve
14 payment in total to equal the energy price, which I think is
15 what we have done in the past. If we run out of reserve, it
16 should go and match the energy price because at that point,
17 reserves are as valuable as energy when you are short of
18 reserves.
19 But we are going a little different place here in
20 that we are also adding those constraints into the energy
21 market clearing price. So I think we have to see if there
22 is any objective criteria to decide not only the total as I
23 said, but the comparison of what's the penalty factor
24 running on a 30 minute reserve, versus non-spin and spin.
25 I don't have a recommendation but I would like to

1 get some of the experts and economists to help me try and
2 understand why we might want to take certain numbers that
3 have been proposed.
4 The last bullet, I thought I was going to be
5 going after the further discussion, I think we might be
6 having on the asset related demand, but I can go now.
7 Is there further discussion on that demand coming
8 up?
9 MR. MONTALVO: Yes.
10 MR. BRENNAN: I can wait for that. Thank you.
11 CHAIRMAN WOOD: Thank you Tim.
12 MR. KATHAN: This may be an opportune time, since
13 you have it on the slide. I'm just curious about the
14 locational aspects. How granular are we talking, the zones
15 in particular the portfolio and the ability for units to be
16 able to be brought in and out as part of that proposal.
17 Could you expand on that a little bit?
18 MR. MONTALVO: Sure. The locations, when we say
19 location are import constrained areas defined by closed
20 interfaces and the import constrained areas we're talking
21 about here are right now the NEMA Boston Region, the State
22 of Connecticut and Southwest Connecticut.
23 Each of these areas, resources are required
24 additional 30 minute reserves are required for protecting
25 against technical contingencies in those areas. So those

1 are the areas and on the system, is the whole of the New
2 England control area.
3 So today when we commit the system we make sure
4 that we have sufficient resources committed to meet our
5 energy needs, our expected spinning reserve needs, our
6 system non-spinning reserve needs and also the local 30
7 minute requirements in NEMA Boston, Connecticut and
8 Southwest Connecticut.
9 So when an offer is made into the locational
10 forward reserve market and a portfolio offer, we will be
11 purchasing 10 minute non-spinning reserve or 30 minute non-
12 spinning reserve. You can always have a 10 minute reserve
13 price to meet a 30 minute obligation because of the higher
14 quality.
15 A set of resources located anywhere in New
16 England can meet the system requirement, but only resources
17 physically located inside our zones or locations can meet
18 the local requirements in that location.
19 If I submit 100 megawatt of 10 minute non-
20 spinning reserves for $5.00 per kilowatt month into NEMA
21 Boston, I can clear against the 30 minute local requirement
22 for NEMA Boston. I can also clear against the 10 minute or
23 the 10 minute system requirement.
24 And any resources now that I designate as we're
25 going on the delivery date, as we go through the procurement

1 period, would have to be resources physically located inside
2 NEMA Boston in order for me to have met my delivery
3 obligations on the forward reserve market to provide 30
4 minute non-spinning reserves in the location, the NEMA
5 Boston location. That's essentially how that would work.
6 I could also sell my obligation to somebody else.
7 Say I have 100 megawatt obligation and I have a resource and
8 the resource I was going to use wasn't working and I have
9 some kind of agreement with a neighbor, like another
10 resource owner, but my resource is not available, I have a
11 contract with you to pick up my obligation. Then you pick
12 up my obligation and would designate his resource. These
13 kinds of things can happen.
14 MR. IDE: I think Mr. Gordon was next.
15 MR. GORDON: Thank you. Thank you for having me
16 here today. My name is Joel Gordon, Director of Market
17 policy with PSEG Energy Resources and Trade. I cover the
18 New England market for the company. As the folks from
19 NEPOOL know, reserves market and RMR operating services is
20 one my favorite topics and I go on this non-stop basically.
21 But today I'm trying to keep my comments very brief.
22 A fair number of times today and we've seen on a
23 number of slides that one of the key objectives of the
24 reserve markets that's been proposed is to provide price
25 signals that encourage efficient provision of system

1 locational operating reserves.
2 And we agree that the goal to get price signals
3 correct is critical to a good market design, and I think
4 that's reflected in the fact that we all agree with the
5 design phase of the reserve market.
6 Earlier today, Gordon outlined as one of the
7 ISO's top priorities of the 2005 wholesale market plan,
8 improved integration of operation decision and market
9 pricing. In here too, we support the need to have operating
10 decisions reflected in the marketplace.
11 The proposed reserve markets, full reserve market
12 on a locational basis and the real time reserve market go a
13 long way in trying to address some of those design
14 objectives but given that we've set for ourselves an
15 objective, a top priority of creating price signals that
16 reflect operating decisions, I think we really should look
17 at the ISO's proposals for the reserve markets, and evaluate
18 it to see if it succeeds in meeting these objectives.
19 Proper design reveals the cost of operator
20 decisions to obtain require levels of reserves. Good market
21 design will reflect the price based on operator actions.
22 The locational forward reserve market takes a step in this
23 direction in that the providers of forward reserves are held
24 out of the energy market based on their bidding in the day
25 ahead market. But, not all resources that are needed can or

1 will be obtained to the proposed locational forward reserve
2 market.
3 In fact, almost every day ISO operations will
4 make additional resource commitments, solely for the purpose
5 of insuring adequate reserve levels in real time. Those are
6 the RMR operating reserves and the cost of these commitments
7 will not be reflected in any market price.
8 The ISO proposal fails to price these resources
9 committed by the system operator to obtain the reserves. I
10 think this is the question, Mr. Chairman, that you had asked
11 earlier. To put the cost of this out of market commitment
12 in perspective, there have been almost $58 million of these
13 charges in Connecticut and $31 million of these charges in
14 Boston since SMD was implemented in March 2003.
15 It's the cost reserves that will not find its way
16 into any pricing of the ISO proposal. There is a disconnect
17 between the price signal and the operating decision.
18 The second point, proper market design
19 compensates those that actually provide the required
20 services. Again, the locational forward reserve market
21 takes a step in providing that compensation. Those that are
22 selected in the locational forward reserve market are
23 actually paid for that service and through the bidding
24 requirements, are held out of the energy markets and are
25 actually providing reserves in real time.

1 Here again, not all resources that are providing
2 reserves in real time will be compensated. The ISO proposal
3 fails to pay some resources committed to provide reserves.
4 The ISO proposed real time reserve market will create real
5 time prices only under two scenarios.
6 The first is when there is a shortage of actual
7 reserves, when we're running out of reserves on the system.
8 And second, if a resource is required to back down to
9 provide reserves, the proposal for pricing in real time
10 ignores the value of reserves not compensated in the forward
11 reserve market, but committed in the day ahead for real time
12 energy market and providing reserves in real time.
13 Moreover, the pricing algorithm for the real time
14 reserve market completely ignores the many hours each year
15 when units have committed online and uplifted to provide
16 operating reserves. These units, which committed to
17 provide reserves in real time, those RMR operating reserve
18 units, also do not reserve compensation for the reserve
19 service that they provide.
20 They receive uplift, but they are not compensated
21 for actually providing the reserves. Again, it's a
22 disconnect between the price signal and the operating
23 decision. A proper market design would base the economics
24 of forward pricing on the expectation of real time pricing.
25 In most markets, buyers and sellers transaction

1 in forward markets based upon expectation of the real time
2 prices and transact on a forward basis based on what you
3 think is going to happen in real time. But that line
4 doesn't exist under the propose additional forward reserve
5 market and the real time reserve market.
6 As Marc put on one of his slides, separate but
7 related. Instead, real time pricing is based on scarcity
8 situations. It is expected to be valueless in all but a
9 very few hours. We're not really expecting to see any
10 prices form real time operating reserves but for technically
11 emergency conditions will be poor conditions.
12 On the other hand, the locational forward reserve
13 market value is determined primarily based on penalty
14 considerations, penalties for nonperformance. The proposed
15 penalties that are under discussion are multiple of the
16 price caps proposed. I would posit that the higher penalty
17 that you impose on a resource, the higher the cost, the
18 higher the price the resource will have to charge in order
19 to accept those kinds of penalties. It has nothing to do
20 with the value of the service that's actually being
21 provided.
22 While I can make the argument that there is also
23 a disconnect between price signals and the operating
24 decision, I think this last point really speaks to me from a
25 market mechanism that connects the forward reserve market

1 with the spot market.
2 In my opinion, that's the day ahead reserve
3 market. Before I go on to the day ahead reserve market.
4 (Slide.)
5 Although this slide is a good one, this one last
6 point regarding the goal of creating the price signal that
7 reflects operating decisions, and that is, ignore the impact
8 of the units that are committed on by the ISO to provide
9 second contingency coverage, in the day ahead or the real
10 time.
11 There is some $80+ million that has occurred
12 since SMD whose has implemented, also acts to dampen price
13 signals in the energy market by effectively adding low cost
14 megawatts into the bid stack in real time. It equally acts
15 to eliminate those shortage conditions that are the drivers
16 to getting the real time prices that are sent to the
17 proposed market.
18 Failing to price these commitments into the
19 market will create inefficient outcomes, not only in the
20 energy market going forward, but in the proposed real time
21 reserve market as well.
22 In order to address some of these shortfalls, we
23 propose in late January, an alternative to the forward
24 reserve market/real time, operating reserve market and that
25 is the day ahead reserve market. I know there is a handout

1 here with a couple of pages that gives a little more detail
2 on it, but at a high level, effective what it does is it
3 takes the locational forward reserve market in the same
4 structure that that has and simply runs that auction for
5 that market every single day.
6 The benefit is that under this arrangement, the
7 ISO is able to purchase all of the operating reserves that
8 it needs through a market mechanism. It can do that on a
9 location-by-location basis, similar to the locational
10 forward reserve market proposal.
11 The resources that are selected in this day ahead
12 auction that I'm proposing would be required to bid into the
13 day ahead market on a strike price that assures they will be
14 providing reserves in real time.
15 Since the ISO will be purchasing all of its needs
16 day ahead, which is about the same timeframe under which
17 reserve commitments are made today, a connection between the
18 operating decision and creating price signals would be
19 enhanced. That's really what the primary objective here is.
20 A day ahead reserve market would attract
21 significantly more resources given the added flexibility of
22 participation in the market. That means more competition.
23 The existing market proposal is only effectively for quick
24 start resources. The day ahead proposal would allow every
25 single resource in the pool to compete on an equal footing.

1 The only distinguishing feature among all those
2 resources that can compete in the day ahead market would be
3 just the cost to provide the service. In my opinion, that's
4 exactly how a market is supposed to work.
5 Finally, a day ahead reserve market can go a
6 long, long way in eliminating the RMR operating reserve
7 charges that we've been experiencing, primarily in
8 Connecticut and Boston. Thanks.
9 MR. MEAD: Can I ask a question. I'm not sure I
10 understand why you think that day ahead reserve prices would
11 be higher than the real time reserve prices that are
12 contemplated under the ISO's proposal. Can you elaborate on
13 that?
14 MR. GORDON: Sure. The real time reserve prices
15 are really an energy scarcity pricing mechanism. The only
16 time the real time market should create a real time price is
17 when there is a shortage of reserves. That's the only time
18 they'll create, there'll be a constraint in the system. It
19 will create a price in the real time market.
20 If you are required to purchase all the reserves
21 on a day ahead basis, units that are available to provide
22 those reserves would have to bit their startup and no load
23 cost, their out of merit operation costs, in order to
24 provide the service.
25 MR. MEAD: Sure, but startup and no load costs

1 are generally not factored into energy or ancillary service
2 prices. They are paid as uplift. It was my understanding
3 that one of the reasons for having a forward reserve market
4 is to find some way to put into the forward price the
5 effective cost of the startup and no load cost.
6 MR. GORDON: That works well in the forward
7 reserve market, but for a very limited, narrow range of
8 resources, potentially the quick start resources that
9 actually don't operate in the real time market but are
10 available to provide reserves when called upon in the 10
11 minute or 30 minute fashion.
12 Most of the reserves that are provided in the
13 poolin real time are online reserves that are already
14 spinning, providing energy to the system or in the case of
15 Connecticut, and in Boston, their RMR units that were
16 committed on the day ahead uplifted and are operating
17 typically at the minimum operating level to provide reserves
18 that way.
19 If those units were able to compete in the
20 market, they would have to price in that uplift cost into
21 their bid.
22 MR. MEAD: Are you proposing to have the day
23 ahead market replace the forward market or supplement it?
24 MR. GORDON: I think it could replace it. But I
25 only introduce this one time at the Markets Committee in

1 late January. We haven't had an opportunity to discuss it
2 further than that.
3 I don't think you would necessarily need the
4 long-term reserve market because you would be able to
5 purchase all the needs in the day ahead.
6 CHAIRMAN WOOD: Marc you had a slide I think that
7 seems to argue why your proposal would in fact stimulate
8 fixed investment in the system where the day ahead only
9 proposal would not. Is that a disconnect between the two of
10 you all?
11 MR. MONTALVO: Yes.
12 (Slide.)
13 The question is how many of the opportunity costs
14 faced by the provider of reserve service are variable during
15 the market period, the delivery period and netting
16 opportunity costs that are variable can then be reflected in
17 the market price. Any cost that are fixed fallout, they
18 will not be priced in the market price. There is no
19 marginal cost associated with that.
20 One of the reasons why you want us to stretch out
21 the procurement period is because it allows you it
22 incorporate more and more costs in the settlement.
23 CHAIRMAN WOOD: And thereby send a signal.
24 MR. MONTALVO: And thereby send a signal. So if
25 we're looking at just the day ahead, one of the opportunity

1 costs association with provision of reserves day ahead,
2 while they are already submitted, you are start up at no
3 load cost, the incremental energy bid, you'll make yourself
4 bid for the provision of energy.
5 Now we have a joint value problem. Are there any
6 incremental opportunity costs associated with the provision
7 of reserves if you are committing a selection for the
8 provision of energy? If you are online for the provision of
9 energy, there are no other uncompensated opportunity cost
10 associated with the provision of reserves because you're
11 already online, you're already dispatched. The only
12 question is, are you economically take an incremental
13 portion of energy at your incremental energy output.
14 And so, unless there is a shortage in real time
15 your reserve price is zero, the day ahead price becomes that
16 expectation market. So day ahead prices should reflect your
17 expectations of shortage in real time and if on average you
18 don't expect shortage in time then you don't expect to have
19 positive prices day ahead either, or they're small.
20 CHAIRMAN WOOD: But Joe, why would you not want
21 that?
22 MR. GORDON: I don't think the day ahead price,
23 as I proposed it is an expectations market. It's a cost of
24 providing reserves market and I can give you three examples
25 that illustrated that a little bit.

1 Let's say I am an on the margin gas combined
2 cycle unit on the market and I expect to get a lot of margin
3 in the energy market and a lot of profit there and I'm not
4 going to be uplifting in the energy market.
5 My reserve price, by turning my unit down to
6 provide reserves would be what I avoid either in the energy
7 market, what I lose in the energy market from an uplift
8 standpoint, or the profit that I'm giving up by not offering
9 to my full economic output.
10 Since I'm a margin unit, it's not going to cost
11 me a lot of money providing that reserve service on a day
12 ahead basis. I would expect the offer price to be low.
13 That's my lost opportunity cost in providing reserves.
14 If I am a very low cost coal plant that if I
15 provide reserves tomorrow I have to turn my unit down and
16 I'm giving up a lot of profit opportunities, say $10.00, I'm
17 going to have to at least charge the $10 to the day ahead to
18 hold my unit back in the energy market to provide those
19 reserves.
20 A coal unit is fully capable of providing
21 reserves real time. It's just a cost associated with doing
22 that.
23 The third example, which is most likely the case
24 in both Boston and Connecticut is, if I'm an old oil fired
25 steam unit that is $10 out of the money but has to get

1 turned on every day to provide contingency coverage, if I
2 have to put myself on and give up all my uplift costs, which
3 is what this proposal would do, I have to recover that out
4 of market energy, the out of market run time.
5 Let's say I have a 40 megawatt limit and I'm $10
6 out of the money, I have to recover that $10 out of the
7 money run in the reserve market. I would have to perhaps
8 charge $10 just to break even in providing that reserve
9 service. In a constrained area, in Boston and Connecticut,
10 that's the level that you're going to have to get to on a
11 significant amount of time because that's the commitments
12 that are actually made today. I think it's something like
13 3,000 hours in Connecticut where these units are actually
14 turned on to provide operating reserves. They have to price
15 their own cost of providing those reserves and that price is
16 reflected in the market. I think you'd have a good outcome.
17 MR. MEAD: If I understand you correctly, this
18 expensive oil unit in Boston, I presume it's going to be
19 submitting an energy bid which include not only an energy
20 bid but also a startup cost in case it happens to be
21 dispatched for energy.
22 But if I understand you correctly, if it's not
23 selected for energy, it gets paid no uplift for its startup
24 costs if it's not selected for energy but it's chosen for
25 reserves, it doesn't get uplifted for startup cost but it

1 would have to reflect its startup cost in its reserve bid?
2 Is that the idea?
3 MR. GORDON: That's the concept. The way I've
4 outlined this is that the reserve market would clear before
5 the energy bids are due. Everybody would be selected to
6 provide reserves before they submit their energy bid. So if
7 they are selected then they put their energy bid in
8 consistent with the way the current forward reserve market
9 works, at a strike price that makes sure they stay out of
10 the energy market.
11 In this case, what would happen is, if an oil
12 fired unit in Boston was selected to provide reserves, let's
13 say it's a less efficient one that's out of the money by
14 $10, they're not expected to run in the day ahead market and
15 the energy market because they are too high on the bid
16 stack.
17 They still can provide enough reserves at the
18 cost that it would be to them to turn the unit on and run
19 out of merit on their own, on their own nickel. That's $10
20 on a megawatt basis, let's say.
21 So their bid for reserves would be, if they
22 expect to be $10 out of the money tomorrow, they don't have
23 any expectation of operating in the energy market, they bid
24 $10 to provide reserve service.
25 If it's the least expensive alternative it make

1 sense to do it that way. What happens today is that very
2 same unit gets put on, in many cases, gets put on by ISO
3 operations because they need a second contingency coverage,
4 instead of actually paying a reserve price for that unit, it
5 paid uplift. And that's the $87 somewhat billion of RMR
6 operating reserve charges that we see.
7 MR. CHADALAVADA: One point to note on this fact.
8 On the things that Joel has mentioned, it's really a chicken
9 and egg problem. The reason you have this out of merit
10 dispatch is because of the lack of bid stack units. The
11 very problem that we're trying to solve will not be solved
12 if we don't have the right signals that go out along the
13 timeframe, which will get you the quick start in the import
14 constrained regions, which will then eliminate the ISO's
15 approach. So it's really which problem you want to tackle
16 first.
17 The ISO's approach has been, let's try to get the
18 forward reserve market to provide the signals that indicates
19 the strong need for quick start resources in the import
20 constrained area and then we can bring in the stakeholders
21 as we go through this. And it's going to take time to get
22 the right incentives in placed and put a quick start unit to
23 be ground, we want to work on an improved operating decision
24 and market prices.
25 That's something we will be discussing with our

1 stakeholders and not be waiting for three years to wait for
2 the quick start resources. So it's a problem that I think
3 we're trying to impress as two fold.
4 Let's send a single to the quick start which w
5 ill fix the out of merit dispatch or in the meantime, let's
6 continue the work on how we can reflect the dispatch into
7 the prices.
8 MR. STINNEFORD: Just to follow up on Vamsi's
9 comments, Mr. Chairman. We have some of these discussions,
10 especially within the Markets Committee and the design
11 document that we have brought it up at the committee and
12 it's been approved by the Participants Committee, has
13 effectively made that decision at least at this point in
14 time.
15 We will go forward with the forward reserve
16 market rather than day ahead real time multi-settlement
17 market. That is reflected in the documents that have been
18 heavily supported by the Committee.
19 MR. BRENNAN: I just had one more than that I
20 think you have to consider if you go to a day ahead or even
21 real time availability. Because the incremental cost is
22 normally zero or close to zero and because you can expect
23 that closer to real time where you might run out of reserves
24 you've got to be very careful about market manipulation and
25 market power concerns and I think you might have more

1 interference in monitoring of the market and you're not
2 going to get an efficient outcome of what truly reflects the
3 incremental costs.
4 Whereas the forward market would reflect those
5 costs and be installed to provide that reserve service.
6 MR. STASZOWSKI: Also, the thought of eliminating
7 the forward reserve market, the forward reserve market, as
8 Vamsi said is important to send new generation but it's also
9 important to provide a revenue screen for existing quick
10 start units.
11 Those units are being relied on by operations
12 such that you do not have to put as many units on at minimum
13 load. Quick start units, gas turbines have very high energy
14 costs. If you are not getting any revenue from the energy
15 market, they need some type of revenue stream to stay in
16 business today.
17 That's another important reason to have a quick
18 start market.
19 MR. MONTALVO: If there are no other questions
20 we'll move on to the discussion of the real time pricing
21 component.
22 MR. MEAD: One final question on the forward
23 reserves. I noticed earlier on, probably an hour ago now,
24 there was a slide that said that the proposal for forward
25 reserves was that a forward reserve seller could not buy out

1 its commitment in real time.
2 Actually I had an interesting discussion with
3 Mario and Tom over lunch about some of these issues. My
4 understanding is that one of the reasons for that is that
5 the cost of replacing a forward reserve seller in real time
6 is often not fully reflected in the price because a big part
7 of that cost, these uplift costs, is the cost of the extra
8 startup and the no load cost that you might have to incur to
9 turn some other unit on.
10 MR. MONTALVO: The way I see it is that in real
11 time, why do we still think the multi-settlement thing in
12 real time pricing makes sense is that -- I'm going to get
13 into this in a bit more detail in a moment, but our real
14 time prices are going to be established as a function of
15 real time pricing algorithms, part of which is the real time
16 operating and reserve requirement right there in there.
17 Whenever those constraints are binding, the
18 reserve constraints are binding because the reserve shortage
19 or resources backed down to provide reserves will get
20 positive prices. But on average, that price is going to be
21 zero.
22 We don't expect reserve shortages typically. And
23 so, to the extent the real time price is expected to be
24 zero. If I was a forward reserve seller, I would have no
25 incentive to actually ever buy, maintain anything to

1 basically offer in the day ahead market if I had the option
2 to buy out my obligation in real time at zero so the forward
3 market would become an expectations market were tuned by the
4 expectation of a zero price in real time and the whole thing
5 unravels.
6 That's our reason there for not allowing the
7 buyout there as opposed to allowing the trading of physical
8 obligations. The forward reserve market obligations in the
9 day ahead.
10 MR. MEAD: One of the concerns I have is to the
11 extent that a forward reserve seller actually has real
12 marginal costs that other energy providers at a particular
13 point in time.
14 As I understand the structure of the current
15 forward reserve market, that forward reserve seller might
16 not be able to provide the energy anyway, because it's
17 obligated to bid above some strike price and if its energy
18 costs are below that, it just can't offer that.
19 I don't understand why that's necessarily a
20 desirable future. It would seem to me that it might be
21 useful to require this forward seller to bid into the day
22 ahead market at zero startup and no load cost, just like the
23 ISO, let it bid its real margin cost for energy and then let
24 the ISO decide whether its cheaper to dispatch this
25 generator for energy or for ancillary services.

1 MR. MONTALVO: But the way we look at it, I don't
2 think actually in the end we would disagree with each other
3 because what we have said, you're going to submit an offer
4 to provide the reserve.
5 In putting together your offer, you have to make
6 the consideration, the threshold price, the energy threshold
7 price, what you expect energy opportunity costs are. You
8 have to consider what your expected commitment costs are.
9 If you are an online resource, you have to internalize your
10 commitment costs and also what you are expected availability
11 is, that is what kind of expected penalties do you face in
12 addition to any going forward costs that you might be able
13 to put into the price, etcetera, etcetera.
14 You take your best estimate of that information
15 and that will become your price. So I think that the
16 expected impact on the energy market naturally gets
17 reflected as an opportunity cost in the reserve price where
18 I think it works out okay.
19 MR. MEAD: I don't want to beat this too much,
20 but like I say, expectations aren't always realized. Fuel
21 prices change. Availability of imports change. I'm having
22 a hard time understanding why in real time, if I have a
23 forward reserve resource whose marginal cost for producing
24 energy is less than the LMP, why doesn't it benefit
25 everybody to let the ISO dispatch that generator for energy

1 and submit an energy bid that reflects that, and choose some
2 other resources for ancillary services?
3 MR. BRENNAN: I think that is allowed through
4 bilateral trading. If that unit decided they do want to
5 participate in the energy market today, and as long as he
6 trades that obligation to someone else who it makes sense to
7 not be in the energy market, it will all work out but
8 someone is going to have that obligation and hopefully that
9 will incent the physical investment in those types of
10 resources.
11 MR. MEAD: I mean certainly the bilateral trading
12 concept, I'm not sure why you would restrict it to that. I
13 need to think about it further.
14 MR. GORDON: I think the whole construct of the
15 forward reserve market is in order to ensure that those
16 reserves in there are real time, you have to keep them out
17 of the energy market until the price in the energy market
18 dictates that you're going to call the reserve and activate
19 the reserve.
20 That's the necessity of having the bid and this
21 highest strike price is to ensure that the resources aren't
22 actually called on in the energy market and don't show up in
23 real time.
24 MR. MEAD: Why do you have to ensure that it's
25 there if you have a cheaper resource that in fact is there?

1 MR. GORDON: I think what you are asking about is
2 why not co-optimize reserves and energy, which is a great
3 question, that's just not the design that's being proposed.
4 But since I have the mike I'd like to add.
5 (Laughter.)
6 That is, the ISO's forward reserve market
7 ultimately portray the two bilaterals but it ultimately
8 results in every day in the day ahead market, physical asset
9 must bid in according to a formula base to come up with its
10 strike price. What I'm proposing in the day ahead market
11 is, every day you go in the day ahead market, a physical
12 asset must bid in and add the same type of strike price.
13 The only difference is how much of those
14 resources has to be bid in in that day ahead market? and
15 I'm proposing that all reserves that are needed in real time
16 get purchased. The ISO's proposal is really those that are
17 30 minute, quick start resources get picked up in the day
18 ahead market.
19 MR. IDE: Marc, I suggest you go ahead
20 MR. MONTALVO: Can you go to slide 28.
21 (Slide.)
22 Our real time reserve pricing is the other half
23 of the forward reserve market. We talked about a bunch of
24 the aspects of the real time reserve pricing mechanism
25 already. So we don't have to belabor many of these things.

1 But quickly, the real time reserve pricing mechanism will
2 seek to optimize real time dispatch and so to meet energy
3 and the system and the local reserve requirements.
4 So basically as I said before, the reserve
5 requirements now are additional constraints from the LP
6 algorithm that solves the real time dispatch. Resources
7 will clear in the energy market and be designated as
8 providing reserves or not in every hour during the day.
9 This is exactly what's done today. Then it will be
10 determined which resources are providing the service in each
11 of the locations. To the extent they are positive prices
12 either because a unit is constrained down to provide
13 reserves or because of a shortage, the prices will become
14 positive and the resources in the areas where the prices are
15 positive would be compensated.
16 As New York has done, it's a very similar process
17 in real time. We have these reserve constrained penalty
18 factors which allow us to have positive prices when our
19 reserve constraints are binding in real time.
20 And so, can you go to 30.
21 (Slide.)
22 I think Tim Brennan mentioned there is a question
23 as to how much art and how much science is involved in the
24 setting of the reserve constraint penalty factors. It is a
25 mixture of both, I think.

1 We have come up with a proposal that was based in
2 part on some of the logic and presented by Dr. David Patton
3 in his filing on behalf of New York for their proposal,
4 reflecting some information we had more specific in local to
5 New England, and also the advise of some of our economists
6 and consultants.
7 So we've come up with some numbers, the basic
8 idea however, and the logic behind the penalty factors is
9 the same, is to make sure that you have cascading values, 30
10 minute reserves, if you're deficient 30 minute reserves, you
11 know, that has a certain impact and the dollar value relays
12 that impact and the effective prohibition on the energy
13 market and the consequences of reflecting those numbers.
14 As you cascade up, you get closer to perhaps
15 running out of spinning reserves. You get closer to
16 essentially one-to-one trade off between energy and reserves
17 at that point. So you end up with this kind of convergence.
18 These kinds of things are all reflected in the
19 numbers that we're going to be working with and participants
20 and explain our numbers and our rational and why they make
21 sense. What the potential consequences of a different set
22 of numbers might be. These kinds of things so there are
23 coming couple of points.
24 (Slide.)
25 Most of this is already been said. I just wanted

1 to note as we discussed a little bit before, there are
2 forward reserve payments and penalties will be assessed in
3 real time. So even though the obligation was established on
4 a forward basis, the payment haven't in real time because
5 performance is measured in real time.
6 Similarly, resources providing reserves in real
7 time, doesn't going to just having provided reserves in real
8 time. That is resources that didn't clear forward but are
9 designated as having provided reserves in real time, will
10 similarly be compensated at that time based on the real time
11 clearing prices.
12 One thing to note is that locational forward
13 reserve resources do not receive any real time reserve
14 prices, and vise versa. So real time resource won't receive
15 the forward reserve price.
16 MR. MEAD: In real time, is it possible that
17 before you went into a reserve shortage, there might be some
18 positive opportunity costs incurred by people who are
19 providing reserves. Will they be paid for that as bid or
20 market clearing?
21 MR. MONTALVO: For resources, now we're talking
22 about resources that are not local forward reserve market
23 resources.
24 MR. MEAD: That means that they are locational.
25 MR. MONTALVO: Locational. Any resource that is

1 backed down to provide reserves, there will be an
2 opportunity cost there that will set the clearing price.
3 That opportunity cost, that will be calculated. That is
4 real time reserve pricing real fast. I want to allow folks
5 to comment on that.
6 (No response.)
7 MR. MONTALVO: All right. The next slide, number
8 34.
9 (Slide.)
10 Deals with integration of demand resources into
11 market design. This is a simply slide of a complicated
12 thing. Vamsi spent a lot of time this morning explaining
13 what the asset related demand was and the infrastructure
14 related needs there to cover it.
15 It's a fairly straightforward change of the
16 market rules with some really complicated consequences that
17 the idea here is that asset related demands that meet all of
18 our technical and metering requirements, they are
19 dispatchable, they can take dispatch signals and respond to
20 electronic dispatch signals and participate in the real time
21 energy market just like any resource.
22 Similarly, if the meet all the technical
23 requirements, metering, etcetera, they can participate in
24 our reserve markets both real time and forward, just like
25 any other resource. As I mentioned before, right now our

1 technical requirements are the same technical requirements
2 generating resources. The resources are being treated in an
3 extremely comparable manner, thanks in large part because
4 what we are talking about are reliability resources for the
5 perfection of the system.
6 Until we have kind of a corpus of evidence that
7 suggests other types of things are equally as good, we are
8 going to wade into it. Thank you.
9 MR. IDE: There are four people who have remarks
10 they'd like to address to you. Mr. Atkins.
11 MR. ATKINS: I appreciate the opportunity to
12 address the Commission today and appear before you. My name
13 is Tom Atkins.
14 (Slide.)
15 I am a load response provider. Today I'm here
16 representing almost 200 megawatts of demand response
17 customers in New England, including numerous Fortune 500
18 companies and large municipalities, virtually all of which
19 are in transmission constrained load pockets.
20 First, I would like to compliment the ISO for
21 following through on their commitment to enhance the current
22 reserve market. In particular, I would like to focus on the
23 goal of increasing demand participation in these markets and
24 give you the perspective of the existing demand response
25 customers.

1 From the discussion today, it appears that many
2 of the stakeholders in this room support the concept of
3 further integrating demand response into the market. But we
4 must be careful not to defeat this goal as we proceed with
5 the details of the market integration.
6 For example, the ISO's current plan for
7 integrating demand response into reserve markets has some
8 serious challenges for load.
9 In order to participate in ASM, a load must be
10 greater than five megawatts and agree to be a special case
11 nodal pricing customer. While the size restriction alone
12 significantly limits the ability of most load to
13 participate, the requirement for load to settle their energy
14 needs on a special case nodal basis is even more
15 problematic.
16 As I understand it, the highest value reserves
17 are those located in the transmission constrained load
18 pockets where contingency coverage is critical to maintain
19 reliability. Which of course is the whole reason to move to
20 a locational reserve requirement.
21 However, demand response assets in those load
22 pockets, which happen to look remarkable similar to quick
23 start peaking units, will not participate in reserve markets
24 because the requirements to settle their energy on a nodal
25 basis actually increases their costs and becomes a

1 significant counterincentive.
2 In fact, of all the load response customers I
3 currently represent, not one is interested in a new ASM
4 design. Fortunately, the ISO has recognized these and other
5 shortcomings in the current ASM design and has initiated the
6 development of the demand response reserve project in
7 parallel with ASM. Henry Yoshimura and Mark Montalvo have
8 referred to this program in their comments today.
9 This demand response reserve project seeks to be
10 more inclusive of the practical needs of demand response
11 customers. For instance, this project does not have a
12 minimum load level for participation. In addition, it does
13 not force an unnecessary link between special case nodal
14 pricing and provision of reserves.
15 Finally, it allows the use of the existing
16 internet based communication system, which has been
17 developed and has been perfectly adequate for reliability
18 based load response programs today.
19 It is my hope that when priorities are being set
20 for the wholesale market plan, the demand response reserve
21 project would get at least the same priority as ASM. In
22 fact, I will note that since the demand reserve project has
23 been developed in parallel with ASM, it does not have to
24 wait for ASM and could be implemented incidentally sooner.
25 In my opinion, this is the best way in the short

1 term to achieve the goal and increasing the participation of
2 demand in wholesale markets. Thank you.
3 COMMISSIONER BROWNELL: Thank you.
4 MR. KATHAN: Actually, to be sure I understood
5 that few hours this morning. The current proposal on what's
6 in here, or will be implemented I guess in June of 2006.
7 Isn't it true there will be a five megawatt resources and
8 would be settled as special case nodal resources?
9 And following up on that, what is the status of
10 the demand reserves project and is that a parallel or is it
11 going to happen afterward? What are the plans of the ISO?
12 MR. MONTALVO: For the ISO related demands right
13 now, they have to, the five megawatts is the size, the
14 general size, and they have to offer or bid, to be at that
15 node, the pricing node. And so those are the size are the
16 technical requirements that I spoke of, the telemetering
17 issues, etcetera.
18 As far as the R&D project that was just
19 discussed, this project is being worked on right now to see
20 what other options might exist and how something other than
21 what's being proposed as right now in ARD might integrate
22 into the system, and what are the issues there.
23 What kind of changes to operating procedures
24 might be require, technical issues and problems and kind of
25 poke at it and see where the problems lie and what can be

1 resolved and so what business rules and procedures might
2 make sense given a broader set of resources.
3 The timing of that is, in part, parallel with the
4 research and development project. When the testing is
5 completed, we have some information to estimate how will we
6 be going forward and what's next.
7 MR. KATHAN: When will that project be done?
8 MR. MONTALVO: I'm not sure whether it's intended
9 to begin. Henry is manager of markets of demand response.
10 MR. YOSHIMURA: I don't have a date. I wish I
11 had a date. I've been working through our folks internally
12 to try to get a team together to assess all of the business
13 units that will need to be involved in order to get the
14 project going because there are settlement implications.
15 There are operation implications, but the way we are doing
16 this, we are looking at doing this project, is actually two
17 subprojects. The one project is a demonstration project and
18 what we need to do with that.
19 What we are attempting to do with the
20 demonstration project is to look at different classes of
21 load, curtailment assets. So you have onsite generators as
22 one type of assets, you have load curtailment assets are
23 weather dependent and you have curtailment that's not
24 weather dependent.
25 These all have different performance

1 characteristics. The first phase of at least one project is
2 to test each one of these to assess classes to assess its
3 performance in response to a contingency reserve type of
4 event.
5 The second project, which is a little less
6 developed at this point, but its also the more important
7 piece is how can we present this aggregated dispersed assets
8 to the control room so they can see them integrated into the
9 supply stack and be able to have confidence that when they
10 deploy them, they are actually deployed in a manner which is
11 similar to any other reserve asset like a 10-minute non-spin
12 spinning asset.
13 So these are the two subprojects that we're
14 scoping out. Because we're still working through internally
15 all the details, I don't have a project schedule at this
16 point.
17 MR. KATHAN: My only couple of comments is one,
18 I'm still kind of wondering why this has to be settled as
19 special case nodal resources. I understand the technical
20 issues and I understand possibly the minimum size. I know
21 at least that there are other markets, including ERCOT, in
22 which demand resources are able to participate as spinning
23 markets. But in ERCOT, I'm not sure they have that same
24 obligation. I'm curious what's the reason for at least that
25 settlement.

1 MR. YOSHIMURA: With respect to the reserve
2 project we're talking about, actually we're going to be
3 running that project as though, we're going to be settling
4 with those resources on a zonal basis. So I can't address
5 this particular nodal aspect.
6 I think one of the issues that led to the load
7 assets being -- from the asset related demand's being
8 settled on the nodal basis, was partially the result of the
9 timing of when the participants got together to talk about
10 special case nodal pricing. It was before we got too far
11 down the road with respect to the design of the ancillary
12 services market. I was involved in the discussion of the
13 special case nodal pricing.
14 What the participants decided was a set of
15 criteria where the dispatchable special case nodal pricing
16 customers would be settled on a normal basis, that
17 particular design aspect was then picked up, I believe, in
18 the design of the ancillary service market. That's about
19 all I can say on that point.
20 MR. MONTALVO: Right. And as the load asset is
21 represented in our systems, a service that is represented in
22 a way that is analogous to the supply resource. The supply
23 resource is offered and settled that node. So our demand
24 asset, which are analogous more comparable treatments will
25 also be settled and bid their resources at node. That's

1 also a representation in our system.
2 MR. YOSHIMURA: Just one other issue, if I may.
3 The issue that Mr. Atkins points out, it's a real issue we
4 have to take a look at but one of the things that could be
5 done that perhaps would address that issue somewhat, is how
6 we look at the zone.
7 If you have, in my research on the zonal pricing
8 project, you could have a situation in which you have a
9 series of nodes which you aggregated together in a zone that
10 are very different. The pricing patterns are very different
11 or you could redo the zones in which a way where the
12 distribution of the mean and the standard deviation of the
13 prices among the nodes within the zone are substantially
14 similar.
15 If we do that, then this issue becomes less of an
16 issue because the pricing for loads within a specific zone
17 will be relatively consistent in that the customers would
18 decide to participate in the substantial piece of the ISO or
19 whatever the reserve market will end up looking like. They
20 would decide to participate in that based upon whether or
21 not they will get a cheaper nodal price, but because there
22 is a benefit to providing reserve product.
23 So that's an issue that is in play right now,
24 particularly in the State of Connecticut. If you have a
25 particular of our system for the nodal pricing, depending

1 upon where you are in Connecticut, you have widely dispersed
2 pattern of nodal pricing among different places in the
3 state.
4 That could be a problem. That could lead to a
5 type of issue that Tom was talking about.
6 MR. ATKINS: I would just comment that demand
7 response fully supports great granularity in a zone.
8 MR. KATHAN: A question for you Tom, which is,
9 you said your customers weren't interested in doing that.
10 Is that driven mostly by the special case nodal aspect or
11 was the five megawatt minimum?
12 MR. ATKINS: It's a little bit of both. I have
13 several customers that are created in five megawatts and
14 that's not the exclusive but the vast majority are less than
15 five megawatts. At some large loads, you know,
16 two/three/four megawatts, can't participate but the decision
17 is mostly driven by the fact that you are providing
18 additional service. Right now, there are reliability based
19 assets that gets called when there is capacity deficiencies,
20 so they are emergency based resource.
21 They're being asked to be called more as a
22 reserve asset. They'd be called more frequently perhaps as
23 much as twice a month and so they are being asked to provide
24 more service and impact their businesses more. Yet they're
25 not necessarily seeing any incentive to do that.

1 In fact, they're seeing their energy prices go up
2 because they have to settle in the load pocket on a nodal
3 basis. They're also concerned that they have a clear
4 commitment to having additional revenue to do this.
5 That opens another sort of Pandora's box as to
6 how you treat ICAP and reserves. Historically they've been
7 separate and distinct markets and they are separate and
8 distinct revenue streams. To the extent you start
9 commingling them, demand response looks at that and sees
10 very little assurance that they'll get any benefits in
11 participating in reserves.
12 If we can keep them distinct, that helps as well.
13 Taking on additional risk, wanting to see additional reward.
14 MR. IDE: I think our next speaker is Mr.
15 Peterson.
16 (Slide.)
17 MR. PETERSON: Good afternoon again. If you look
18 at the slide I'm just going to hit briefly on each of the
19 points on the slide. Demand is market resource. Jim Wood
20 talked quite a bit about that this morning. It seems
21 undisputed everyone who looks at the wholesale electricity
22 markets that the more you can use the demand side resources,
23 and the huge benefits that will come from those resources.
24 So there is no dispute that we want to try to
25 include demand resources. ISO New England is committed to

1 that. One of the issues that comes up in what is called the
2 technical aspect of demand resources, the small size, the
3 seasonal issues that apply to some of these resource
4 providers.
5 When the ISO describes accommodating demand side
6 resources, they kind of say well, they're kind of apples and
7 oranges and we'll try to figure a way to treat them
8 comparably. Within the power pool now, there are a lot of
9 different kinds of resources.
10 There are slow ramping up coal units. There are
11 nuclear units that take six or eight week outages every
12 couple years to do refueling. There are run-of-the-river
13 hydros. There is ponding hydro, there are gas fired units.
14 You can think of those as apples and oranges and peaches and
15 pears, but they are familiar and they're familiar to
16 everyone around the country because they're growing
17 everywhere in the country. ISOs and RTOs know how to deal
18 with them.
19 Demand resources are pineapple. They're from an
20 exotic place like Hawaii and people aren't familiar with
21 them. It's hard to get your hands around them because
22 they're prickly. So, in order to accommodate demand
23 resources, you have to maybe stretch the envelope a little
24 bit to accommodate some of the technical aspects. But there
25 is no denying that these are real resources and energy

1 efficiency resources might some day come to be accepted,
2 included as a resource that RTOs can rely upon, particularly
3 in areas that have local problems, load constraints,
4 transmission generation deficiencies.
5 In order to accommodate these unusual fruits, we
6 need to embrace pilot projects and special studies. The
7 demand response reserve project. In a recent order, FERC
8 correctly said why can't we fully integrate this program?
9 Excuse me; that's the day ahead load response program. Why
10 can't we fully integrate it?
11 Yes, that's the ultimate goal is to fully
12 integrate it. But if you have all these technical issues
13 the ISOs and RTOs have to get their hands around, then I
14 think you need to embrace some special programs in the
15 interim so we can get some of the benefits in place, learn
16 more about these and eventually fully integrate them.
17 It gets to my next point, which is now what do
18 you do about assigning cost. NEPOOL always has problems
19 with any programs when we have to decide how to allocate the
20 cost. The two that I'm most familiar with is assign the
21 cost to network load. And half of them says, no, no, no,
22 that's not the appropriate assigning. Assign it to real
23 time load obligation and the other half of the room says,
24 no, no, no, that's not t he right signing.
25 So we argue endlessly, even if we decide it's a

1 good program, is how are we going to assign the cost. And I
2 think for these early development projects, these special
3 cases, if we can find a way to call them market development
4 costs and put it in the capital budget, and take them out of
5 the NEPOOL debate of who is getting the benefit of who
6 should get pinned with the cost, it would also be easier to
7 get this through the stakeholder process.
8 Provide demand resources a place at the table. I
9 want to compliment the Commission on having done that in the
10 RTO order by creating the alternative resources sector. It
11 was activated in February 1. There are six members of the
12 alternative resource sector. Two of them are demand
13 resource, energy efficiency resource providers.
14 There is another application pending for another
15 demand resource provider to join the AR sector and there are
16 a couple of other clients that my company is working with
17 trying to get them to join the sector.
18 So as these new participants come in, they will
19 have a place at the table and they'll have a way to advocate
20 for their interests as Tom Atkins is the new member of the
21 AR sector. The following point is the leadership that FERC
22 has already provided in your orders is critical and the
23 ISO's leadership is also necessary as we explore the new
24 ground and try to define ways to incorporate what everyone
25 seems to agree are very beneficial resources.

1 But we are not sure yet exactly how to achieve
2 them in the fruit basket of all the resources that we need
3 to have available in New England. Those are my comments.
4 Thanks.
5 MR. IDE: Mr. Chairman, our next presenter will
6 be Mr. Weishaar.
7 MR. WEISHAAR: Thank you.
8 (Slide.)
9 I can't wait to tell my clients I have a prickly
10 fruit that we should be entertaining.
11 CHAIRMAN WOOD: Welcome to the club.
12 (Laughter.)
13 MR. WEISHAAR: I think just three principles or
14 concepts that seems to have pervaded all the demand response
15 discussions today. Those are functional equivalence,
16 resource parity, and equilibrating opportunities for
17 extraction of value.
18 If we stick to those three principles, as we look
19 at pilot projects or incorporating demand response in the
20 ancillary service markets, I think we will be sell served.
21 I do want to step back though and offer two kind of broader
22 or macro comments.
23 I'd like to applaud the ISO's agreement to
24 conduct analysis and quantification of cost and benefits in
25 phase two of the ancillary service market. I think as we

1 look at these market design change, it is helpful if the
2 outset of the stakeholder process, that that's done so we
3 have a clearly define problem, we know exactly what we are
4 tackling and we can look at the cost and benefits of various
5 options.
6 The other point I'd like to make is, it seems
7 that since the '98/'99 timeframe, we have gone through a
8 tremendous amount of market rule change. Each or every
9 other year in our wholesale markets plan, we are identifying
10 enhancements that are needed to the market or incremental
11 changes that are needed to the market.
12 I think, as a macro comment, we would be well
13 served to identify what is the end state. I don't think we
14 have identified the end state thus far. We don't know
15 exactly what we are working toward. It seems to me that
16 what we are doing is reacting to situations and patching the
17 market as we go along.
18 I agree with the concept of having a business
19 vision and that we have to break it down in chunks. But,
20 there is also I think value in trying to come up with a
21 long-term vision so that we know exactly where we're going
22 to be at the end of the day or what we need in terms of
23 total design in order to label this a complete functioning
24 competitive market. I urge you to consider that as well.
25 Thank you.

1 COMMISSIONER BROWNELL: Bob I don't disagree but
2 it feels like this is a never-ending quest. But, if you
3 really look at markets, they are dynamic, and they are in
4 the process of continuous change and evolution. And market
5 evolution, when you are starting largely with monopolies and
6 some antiquated laws that allow you to make more surgical
7 decisions, it's hard for me to know when we know when we've
8 got what we wanted to get, and it also worries me that we
9 declare victory too early instead of pushing ourselves
10 toward constant innovation.
11 I agree with you that there is a balance between
12 change for change for change and we need better
13 measurements. But I'm really not sure that defining the end
14 game is possible or even desirable. But I don't know the
15 answer to that but I think it's something we need to think
16 about because we're not creating the next version of
17 monopolies for tomorrow, as I know you know.
18 MR. WEISHAAR: I appreciate that concept. It is
19 not an easy issue and I think thus far we haven't really
20 done that. I know that there will be evolution but at the
21 same time, we needed to make sure that we are changing and
22 working toward a long-term goal and not reacting to
23 situations and making changes for the sake of change.
24 COMMISSIONER BROWNELL: And it is a function of
25 getting the right measurements, I think.

1 MR. WEISHAAR: It's a benchmark issue as well.
2 MR. IDE: Mr. Chairman, our final prepared
3 speaker is Mr. Brennan who is going to finish the remarks
4 that he started earlier.
5 MR. BRENNAN: Going back to my last bullet of
6 three that I had on my slide.
7 (Slide.)
8 Related again to the demand participation in the
9 market. It is important to put in that direct participation
10 to increase the efficiency in the market. Someone mentioned
11 earlier that they must be integrated and dispatched with
12 complete equality and I agree with that. And although I
13 agree sometimes you may need a pilot, that we shouldn't be
14 having pilots for the sake of having pilots.
15 We recently had a proposal come from the ISO and
16 I commend them for pushing more demand response. But as I
17 remember, I think it was on the 30 minute market. They
18 wanted to do like a pilot program for a little while before
19 they put it in.
20 I think everyone in the Market Committee was
21 saying, can't we just right from the start have them bid
22 directly against the other markets? There didn't really
23 seem to be any reason not to, and the sooner we can get
24 direct participation, and influence on the clearing price,
25 you won't have any arguments, I don't think, about who

1 should pay.
2 To the extent they are directly affecting the
3 clearing price, the ones exposed to the clearing price,
4 those are the ones that I think would be happy to pay if
5 its for reintegrated and treated equally like any other
6 resource.
7 The one concern I've had related to the reserve
8 market is this new asset related demand. We've heard a lot
9 about it in the last half hour. It sounds to me that
10 perhaps the demand and the reserve product alternative might
11 solve it for me. But I'll tell you what my concern is, when
12 we all agree to a special case nodal pricing, we did have
13 those limits of individual end use customers on a certain
14 size by megawatts and no aggravation was allowed.
15 And Bob mentioned earlier today that, you know, a
16 reason for that might have been metering, post utility
17 concerns with metering and things like that. But there are
18 other reasons why we don't need to bring nodal pricing
19 choice all the way down to the residential customers.
20 One concern is that if you have nodal pricing for
21 everyone and those at the lowest nodes choose it and you
22 start driving up the average price, and as a company who is
23 trying hard to develop retail competition, we wouldn't want
24 something like that to interfere. We would not want someone
25 to have agreed to serve a bunch of customers and then a

1 bunch of residential customers because they happen to be
2 near a node, decide to aggregate together, take the nodal
3 pricing, drive up the aggregate price in the zone.
4 If that's the right market efficiency outcome, I
5 guess you should allow it. But I think one thing we've got
6 to keep clear in my mind, none of us will ever choose where
7 to live based on their electricity price. I find that hard
8 to believe.
9 When you are looking at a house, you're either
10 looking at the school system and the cost of the house.
11 You're not going to be seeing whether your electric bill is
12 $55 or $65, I don't think.
13 So unlike a generator or large investor customer,
14 that nodal pricing is important for market efficiency. I
15 don't think we need to carry it all the way down to the
16 residential customers.
17 My concern with the asset related demand was, we
18 had put that limit in there for a bunch of those reasons I
19 had just talked of, five megawatt no aggregation, the asset
20 related demand now seems to say you could get nodal pricing
21 through aggregation. Now the intent was to get more
22 participating from pricing and demand response.
23 My concern is, I don't like to be a loophole for
24 a bunch of neighborhoods to all get together and say I'll
25 pretend I'm going to participate in the demand response

1 program in order to get by that restriction on special case
2 nodal pricing.
3 We'll all aggregate together, choose nodal
4 pricing, but I won't really be participating as an asset
5 related demand in the demand response program. I think we
6 can solve that problem but we have to beware of it. And
7 like I said, maybe this alternative that we are going to
8 work on will solve it. Thank you.
9 MR. ATKINS: If I could react just one section to
10 the first part of what Tim said. I want to support Paul.
11 Sometimes people think demand response is a box you check.
12 I want to do demand response. What we have to do to
13 incorporate it? Well we have these apples, pears, and
14 oranges categories and it fit really well for generators.
15 So just through the demand in one of those, you
16 pick it, you've got to be in one of these three and my
17 suggestion is when we do create markets and try to
18 incorporate demand, that it is not an aberration of the
19 market to recognize that it is pineapple and may need some
20 special accommodations.
21 That doesn't mean that it's not an equivalent
22 resource. It means that it needs the same kinds of
23 provisions that different kinds of generation do.
24 MR. IDE: Mr. Chairman, if I may. To summarize
25 the stakeholder process and where it is in phase two.

1 Next week, NEPOOL's Markets Committee will begin
2 its work almost on a blank sheet. It's got a design basis
3 document that has the two sentences that you've seen up here
4 earlier.
5 One related to the objective of the market and a
6 very high level description of the market and it raised a
7 forward reserve market with real term reserve pricing should
8 be pursued to advance to advance the region toward the
9 objective.
10 That's really the sheet of paper that we're
11 starting to work with. So we'll begin to take up some of
12 the issues that you've heard discussed and debated a little
13 bit today, starting next week.
14 The rest of the process, ISO New England has
15 committed to provide to the NEPOOL stakeholders. There is
16 also the studies that you've heard discussed. Additional
17 White Papers and the background material by May 1. Between
18 May and August the stakeholder process will be working to
19 develop revised rule changes and manual changes. The rule
20 changes, the intent is to file those with you, hopefully in
21 September.
22 That's the schedule that's underway, and we've
23 got our work cut out for us, I think, over the next few
24 months. But that's where we're at. Thank you.
25 MR. STINNEFORD: If I could just add to that. On

1 behalf of the Markets Committee first of all, I want to
2 thank Commissioner Brownell and Chairman Wood for their time
3 and patience today and also offer the invitation to the
4 extent that you enjoyed a taste of the pineapple here today.
5 (Laughter.)
6 MR. STINNEFORD: You can join the rest of the
7 fruits and vegetables next Tuesday and almost any Tuesday.
8 We'll be happy to take you.
9 (Laughter.)
10 CHAIRMAN WOOD: As we always do, we'd like to
11 offer the opportunity for anybody who is not sitting at the
12 front table here today to offer any suggestions or advise or
13 commentary or questions. If you do, come up to the
14 microphone now and feel free.
15 (No response.)
16 CHAIRMAN WOOD: If not, anyone else? Gordon.
17 MR. VAN WELIE: I did have something I'd like to
18 offer. If there is nobody else that wants to talk.
19 (Laughter.)
20 MR. VAN WELIE: It's not because I want to keep
21 you from your flight, just a few points. I want to bring us
22 back to where I opened the discussion this morning in terms
23 of wholesale market value.
24 From ISO's point of view, we want to get
25 something done the first of October as well as the June

1 timeframe for phase two of the ASM market. That's something
2 I'd like us to really get focused on.
3 I think what I found very good about the
4 discussion today, I think you've got a good sense of how
5 broad and deep some of the issues are that are facing us and
6 we've got six months in which to drive this to resolution.
7 And in order to drive it to resolution, so that
8 we can get something done, the issues you heard about today
9 either need to be resolved or deferred for future
10 implementation. That's really the choice that we have
11 between now and August.
12 The reason I said either have to be resolved or
13 deferred and agree that this is the approach is that the
14 alternative is some form of litigation and that will ensure
15 that we don't get anything done by next June. So I'm very
16 anxious to avoid that outcome.
17 So therefore, I offer to involve some of your top
18 people in this discussion, I think is going to be very
19 necessary to help us converge on some of these issues and
20 make those decisions as to what can be implemented by next
21 June and what will have to be put into the bucket of things
22 that are still issues to be addressed going forward.
23 So we've got two constraints. One is the ISO
24 constraint, the resource constraint and the failure
25 constraint that I mentioned earlier this morning.

1 The one I didn't mention however, is that we also
2 have a constraint with respect to our stakeholder process.
3 The people sitting around the table here, as they will tell
4 you, are typically involved in several committees. The
5 Reliability Committee, the Transmission Expansion Planning
6 Committee, the Participant Advisory Committee, the NEPOOL
7 Participants Committee, the Markets Committee. These people
8 often spend a large part of their time involved in many of
9 these committees.
10 We can only process so much work through that
11 committee structure in any one period of time. I think what
12 we need to do, and I think Chuck and Eric are capable at
13 cracking the hoop within the Markets Committee is to try and
14 drive some kind of funnel approach reasonably early on in
15 the discussion so that we do achieve a result by the August
16 timeframe.
17 And I think it would be very useful if you could
18 help us get there. Thank you very much.
19 CHAIRMAN WOOD: Gordon, thank you. I do want to
20 say, seeing these guys, I just want to say as far as David
21 Mead, who is the David on the far end, David and I worked
22 together when I was here some 15 years ago. David has
23 certainly earned my respect then with the gas issues and
24 that industry has had a very successful transition and David
25 is very much in the forefront of that.

1 We're lucky to get Dave Kathan in more recent
2 years to come work at the Commission with a lot of
3 expertise, particularly on the issues we talked about, he is
4 in fact our champion and I've designated after Allison
5 Silverstone, I've designated certain staff people be
6 champions in a lot of the really more front end market
7 issues such as the DREE issues.
8 And so David is not only our expert and a good
9 guy to work with, but a champion on those issues and the
10 Commission is trying to push them to equality with the
11 supply side issue with which we have a long familiarity.
12 So I did want to just emphasize in closing, we of
13 course thank you for your hospitality as always. We really
14 do enjoy the challenges of this market. It has a long
15 history of doing good things, work through a lot of
16 problems. There are still problems to be worked through,
17 including one down at our Commission.
18 (Laughter.)
19 CHAIRMAN WOOD: I think that probably sent a
20 pretty good signal about the need of consensus because I do
21 know that that one is not going to consensus, it will go to
22 litigation, the Commission will make a decision, it will go
23 to court and that's the way it's going to work.
24 (Laughter.)
25 CHAIRMAN WOOD: But everything else doesn't have

1 to. The big dollar money issues tend to do that and I think
2 we're realistic here and please note that that's what
3 regulators do.
4 You mentioned this to Don in the stakeholders
5 committee yesterday, that we're going to just get on the
6 issues that are retractable and they tend to be money
7 issues. Specifically they tend to be cost allocation
8 issues, which I think, one of you guys in the middle here
9 mentioned a moment ago, and that's okay, that's what we're
10 paid to do. So just don't let that ruin the family harmony.
11 Just send it out to us and we'll go to court and get it over
12 with.
13 (Laughter.)
14 CHAIRMAN WOOD: We do need demand in the market.
15 It is necessary for an efficient market and please keep that
16 in mind as you are all committed to do in setting priorities
17 there that, really that is a vision thing.
18 A longer term goal is to get to that point
19 because a lot of the other artifices that we put in place to
20 substitute for its absence tend to follow why these markets
21 become simpler or transparent and more customer benefiting.
22 This isn't empty promises. The same things
23 happened with another big kid all the scene, which is wind
24 power. There is not a lot of it up in this particular
25 region, although I understand offshore there may be.

1 (Laugher.)

2 CHAIRMAN WOOD: I as a wind advocate support that
3 but in my home state of Texas, wind has kind of made its way
4 onto the scene in a big way. Out west we are working with a
5 lot of tariff changes and mindsets are changing as the
6 technology is changing. This can be done. New people can
7 be welcomed to the table and become full partners in a
8 pretty quick dispatch so I would just look at wind as being
9 a very good example there.

10 I appreciate the concerns that you all express
11 regarding the need for certainty. We hear that in
12 everything that we do. In the gas industry, the
13 hydroelectric industry and certainly the power industry and
14 facing changes when they are needed and as they are
15 appropriated, as they are cost effective.

16 We mentioned that in our White Paper after the
17 SMD rule we heard a lot back about. Doing market design
18 changes not just because it's in the SMD rule but because
19 they made sense for the market. That is a great
20 contribution. It is actually resonating a lot across the
21 country in a positive way and I appreciate that the ISO now
22 is able to provide a lot more focus and leadership with
23 regard go getting real numbers that people could make
24 business decisions on and can use in the deliver prices at
25 the collaborative level.

1 So I appraise you for that and encourage you to
2 even crisp it and refine it and make it a dispositive factor
3 because we are asking and we will continue to ask for that
4 as part of the filing when we see large changes coming in
5 here.
6 I'm encouraged that the design of market changes
7 that we talked about here today are intended to replace the
8 band aids like RMRs that are necessary to do but not things
9 you want to be hooked on for long term because they do have,
10 as we all know, downsides to them. That's important.
11 I will just say personally I don't know Nora if
12 you share that as much, I do worry when we have a dissonance
13 with the neighboring market, because New York market has
14 gone a different route on the software that you all and PJM
15 has done. And this is the same sermon I preached to them.
16 When I hear the forward reserve market approach
17 is different than the co-optimization of reserves approach
18 that's been taken there, you're not so far down the road
19 that you can't rethink that. But if that's where you are,
20 the Commission will work with you. The guys know how to ask
21 the questions that we would otherwise ask but just take one
22 more thought about that before you jump in.
23 They happen to have done it first and it doesn't
24 necessarily mean it's right or wrong but if they work
25 equally well, and I don't know if they do or they don't, but

1 if they work equally well, it will surely make sense to
2 harmonize with you neighbors, they are in the same NERC
3 region and I expect over time those markets will grow closer
4 and closer together, commercially and otherwise.
5 Finally, on the substance. The importance of
6 location incentives. I think you know we have got the case
7 pending. It's on our docket so I can mention it here on the
8 record. But the Commission has looked awfully hard at what
9 kind of incentives are needed to get the right
10 infrastructure at the right place at the right time.
11 And I appreciate that's just a part of what we
12 talked about in the last part of the afternoon here with the
13 forward reserve market having a locational component to it.
14 That is as it should be. I don't see any other way, unless
15 you have a full deliverability requirement for all
16 generation attached to your grids. You used to have it but
17 got rid of.
18 PJM has that so their locational aspect is late
19 coming. Even they are coming around to it but they do have
20 the requirement to have a fully deliverable generation
21 interconnection in their grid.
22 I think the locational aspects of what we're
23 doing on not only reserves and energy, but on longer term
24 reserves planning and all that is here to stay. We've got
25 to find an appropriate way to introduce it but I think we've

1 got to get used to it. And so I'm very heartened by the
2 fact that you all -- it doesn't need a Commission on it to
3 go do it. You know it's go to work because you live here
4 and you've got to make this work.
5 I want to thank our dear friend, and I've known
6 Anna as long as I've known probably anybody in this entire
7 room. Just a sharp person. Worked in the gas industry
8 again, which was where she and I got to be buddies. A
9 growing she is now, in charge of our staff that work for the
10 New England and the Northeastern markets.
11 Now that's a full plate and I think you all know
12 that certainly with New York and PJM markets off the RTO ISO
13 level, it's an exciting place to be but it's a pool effort
14 so I appreciate your support for Anna and the team and look
15 forward to them being much more integrated with you all than
16 we've been in the past.
17 I appreciate Don Sipe and the group yesterday
18 coming up with the suggestions that Nora be nimble enough to
19 figure out how to pull that together and make it work and we
20 look forward to that as well.
21 When you all need us we're here. It's important
22 to solve these things up front. Four hours, whatever, six
23 hours for us. That's as much time as we spend on an order.
24 That is going to have -- well, hell, a whole lot less than
25 we spend on the LICAP orders.

1 (Laughter.)
2 CHAIRMAN WOOD: And those aren't even done yet.
3 Finally there was an interesting email today that the staff
4 sent about the New England governors looking for the future
5 on particularly energy issues and certainly we admire how
6 well New England bipartisan approach has always worked
7 through issues and I wanted to just second that.
8 But I always want to say that an important piece
9 of the mix here is, this is a high cost region of the
10 country for electricity, and we shouldn't forget that. It
11 is fun to go to the Midwest and talk about the coal fire,
12 liquid fire power being the cheapest in the country, of
13 course, parentheses, yeah and all their soot comes up here
14 and drops on you all, but I'll get away from that.
15 But solving the core problem here it is important
16 to fix these issues to deliver efficiency, but one of the
17 very core issues that we haven't talked about today and it
18 wasn't on the docket, but how to actually get fuels here to
19 this part of the country. It's not a fuel region. You
20 don't sit on coal deposits, you don't have natural gas
21 deposits, there is not a real strong support for additional
22 nuclear power plants or expanding of hydro plants.
23 We unfortunately having to rev back on megawatts
24 that are generated from hydro electricity up here, although
25 there is quite a bit in this part of the country more than

1 anywhere, except the west. So you're kind of stuck with
2 coal, which is not popular here, or gas. Folks, we got to
3 get some gas up here.
4 I know this isn't the gas agenda but you folks
5 are the ones who are paying the high prices for electricity
6 up here, and about the only place I've seen in the
7 foreseeable future that its coming from, other than the Cape
8 Cod windmills, is going to be natural gas fire plants. And
9 gas just doesn't appear out of the ocean. Methane hydrates
10 might be fun, but they're all about 20 years away. We got
11 to get you all some gas here.
12 So we've got pending dockets in our case that
13 relate to New England Fire. New England cited facilities
14 and I'll just kind of leave that message where it is.
15 We always make these things work because of one
16 woman, she is there in the back, Sara McKinley. Sara we
17 always appreciate what you do to pull these workshops
18 together and make them productive and focused.
19 So you all have a good weekend and we look
20 forward to seeing the filing later this month and another
21 one later on this year. Have a good day.
22 (Applause.)
23 (Whereupon, at 3:55 p.m., the technical
24 conference was adjourned.)
25