Federal Energy Regulatory Commission

Date: May 9, 2016
Volume:

Case: In the Matter of: Algonquin Gas Transmission, RP16-618-000

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BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of :

ALGONQUIN GAS TRANSMISSION : RP16-618-000

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Monday, May 9, 2016

The technical conference in the above-entitled matter was convened at 10:00 a.m., pursuant to Commission notice and held before:

COMMISSIONER CHERYL LaFLEUR

COMMISSIONER COLETTE HONORABLE

COMMISSIONER TONY CLARK

FERC STAFF:

KAMALA JAYARAMAN
FRANK SPARBER
MICHAEL GOLDENBERG
ANNA FERNANDEZ
RICHARD HOWE
LINDA HEARNE

PRESENTERS:

KATHLEEN BARRON, Exelon
CRAIG ADAMS, Calpine
JAMES DALY, Eversource Energy
STEPHEN MCCAULEY, National Grid
TIM BRENNAN, National Grid
RICHARD KRUSE, Spectra Energy
JOHN RUDIAK, Connecticut Natural Gas
JOHN COYLE, Duncan & Allen
JOE DALTON, ENGIE Gas & LNG
VINCE MORRISSETTE, Repsol Energy
TOM LOCKETT, Tenaska

Court Reporter: Alexandria Kaan, Ace-Federal Reporters

(10:03 a.m.)

MS. FERNANDEZ: Good morning. Welcome to the technical conference in Algonquin Gas Transmission, Docket No. RP16-618-000. My name is Anna Fernandez and I will be moderating today's conference. In its March 31st, 2016, order the Commission directed staff to convene this technical conference to examine the issues raised in the protest and comments regarding the February 19 filing made by Algonquin Gas Transmission. In that filing, Algonquin proposed to exempt, from the capacity release bidding requirement, certain types of capacity releases of firm transportation by electric distribution companies that are participating in state-regulated electric reliability programs. Issues to be examined at this technical conference include concerns raised regarding the basis and need for the waiver. As indicated in the noticed agenda, we have several party representatives making presentations here today. Due to the number of parties requesting to make presentations, each presentation will be limited to 15 minutes to provide sufficient time for discussion. Staff, speakers, and audience members will have an opportunity at the end of each presentation for questions and comments. For those watching the live webcast, speaker materials are available on the Commission's website. We plan to break

for lunch at noon, and we will reconvene the conference at 1:00 p.m. Also, at the end of today's technical conference we will discuss the schedule for post technical-conference comments.

I would also like to ask anyone who has their cell phones to turn those off at this time. And now I'd like to welcome our Commissioners, and first I'd like to welcome Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you very much, Anna, and thank you to everyone for being here and the panelists for coming to share your views, and especially thank you to staff for pulling this together pretty quickly. I'm really looking forward to the discussion today on Algonquin's capacity release proposal.

I thought I would just make a few framing comments on what I hope to get out of today's conference. Obviously, we're here to discuss Algonquin's proposed exemption from the Commission's capacity release bidding requirements. While I recognize that this proposal relates to the development of the Access Northeast project in particular, today's conference is not intended to address whether we should authorize development of that project. Rather the conference relates to the capacity release proposal that Algonquin has put forward. As I've said repeatedly, I think we should be flexible in considering

tariff structures for pipelines to support the development of pipeline capacity if and where it is needed, but we can only exercise flexibility within the limits of our authority under the Natural Gas Act. What I'm most interested in getting at today is the following two questions: The first is why the proposed capacity release exemption is needed to achieve the stated objectives of the electric distribution companies of increasing the reliability of gas supplied to the region; and the second is whether there are changes that can and should be made to the capacity release proposal to ensure that it is in the public interest under the Natural Gas Act, to see where we can get to from here. I'll of course consider any issues that are raised today in the posttechnical comments and in later dockets as well, but I hope we particularly hear about those things. Thank you very much.

MS. FERNANDEZ: Thank you, Commissioner.

Next I'd like to welcome Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you. I'd like to yield to Commissioner Clark. He says go ahead. Good morning everyone and thank you Anna. Thank you to the staff and I also want to thank all of the participants and those of you who traveled from near and far to be with us today to explore this issue with the Commission.

In my mind, this capacity release proposal

raises novel concepts, and therefore I agree that a technical conference would be a great opportunity to explore your views of whether this would be a prudent one, and I'm delighted to take in this information with all of the interested parties. I'd like to thank all of you who have worked tirelessly on this issue. We know that coordination is a challenge for you, particularly in your neck of woods, and it's a priority for us here at the Commission. I think because of how dynamically the electric industry and the sector is shifting, it really requires heightened dedication and work on our collective parts, and I look forward to undertaking that effort with you. As you all know, the Commission has recently directed several improvements necessary for gas-electric coordination, and I'm raising coordination here because I think this proposal could be an attempt to be creative in how we address the needs in this sector. And I've certainly, along with my colleagues, been watching the markets very closely to see how the changes that relate to how dynamic the markets are moving will play out. The parties here to be commended for working together to find new ways to resolve natural gas contracting issues -- and I must say for a number of you traveling on Mother's Day to get here, we appreciate that very much. We also recognize that electric generators generally have very different

natural gas needs than more traditional pipeline customers, and we see gas contracting issues materialize more frequently here at the Commission, and I believe that it warrants our continued attention.

Finally, I look forward to the discussions today and hearing more about this unique solution. I appreciate those of you who have put forward comments; we have certainly taken those in and will keep them in mind. And if I'm not in the room throughout the day today, I will have -- a staff member here will do it, someone here, in case anyone would need to reach out to me in particular. Thank you.

MS. FERNANDEZ: Thank you, Commissioner.

Next I'd like to welcome Commissioner Clark.

COMMISSIONER CLARK: Good morning and welcome everyone, thanks for traveling to be here for those of you who came from out of town.

Just a couple of opening comments on my part. I think both my colleagues framed the issue very well. What I would say about what I'm hoping to get out of the conference is this: I'm hoping we're able to study the issues that are teed up here today in the context of the Natural Gas Act. And I understand this can become a bit of a fine line in looking at some of the comments that Commission has received thus far, seeing that line blurred

a little bit. But I contrast that with the impacts of these proposals on the Federal Power Act and electricity markets, so on and so forth. I have expressed concerns from time to time over the last few years -- I know others have as well -- about the functioning of electricity markets, especially in unbundled regions of the country where you have far-reaching fleet -- of generators, and how that is working in the context of the Federal Power Act. But to me, today this isn't really that particular discussion. What we're talking about today is within the context of the Natural Gas Act requirements that FERC has traditionally required, and whether those need to be tweaked or not or whether they can be tweaked given the industry and the state of the law, given the proposals that we have in front of us. So really what I'm going to be looking at today at least is going to be focusing on those issues related to Natural Gas Act itself. There's going to be lots of time in the future to talk about the Federal Power Act and how wholesale electricity markets are working, not just in the context of these proposals but by lots of other things that are going on, especially in the restructured eastern markets of the country. But that debate is probably for another day at least. So thank you all for being here, I look forward to a very good discussion today.

MS. FERNANDEZ: Thank you, Commissioner.

Now I'd like to introduce the other staff members here today. Today I'm joined by Michael Goldenberg from the Office of General Counsel, Richard Howe from the Office of the General Counsel, Frank Sparber from the Offices of Energy Regulation, Kamala Jayaraman from the Office of Energy Market Regulation, Linda Hearne from the Office of Energy Policy and Innovation. I'd like to make a standard disclaimer that staff's comments today do not necessarily represent the views of the Commission or any individual Commissioner.

And with that, I think we're ready to begin our presentations. I'd like to welcome to our table our speakers, and thank you for being here. Our speakers today include Richard Kruse from Algonquin Gas Transmission/Spectra Energy, James Daly with Eversource Energy, Tim Brennan with National Grid, Stephen McCauley with National Grid, John Rudiak speaking on behalf of New England local distribution companies, John P. Coyle speaking on behalf of the Massachusetts Attorney General, Craig Adams with Calpine Corporation, Joe Dalton with ENGIE Gas and LNG, Kathleen Barron with Exelon Corporation, Vince Morrissette with Repsol Energy North America Corporation, and Tom Lockett with Tenaska Marketing Ventures. I'd like to remind all of our speakers to please turn on your

microphone before speaking so those in the room and watching via webcast can hear your comments. And I'd also like to ask the speakers that you turn your table tent on its side when you'd like to make a comment or ask a question so I can recognize you to speak.

And now I'd like to invite our first speaker, Richard Kruse, to begin his presentation.

MR. KRUSE: Thank you for the opportunity to speak for Algonquin. We have some slides, PowerPoint. In any event, thank you very much. We see that the issues that are raised in this conference -- good morning. Thank you for the opportunity to turn my mike on, and thanks for the reminder. We see the fundamental questions that this filing has raised is really boiling down to two questions. We have four up there, but really there's two, particularly in light of the comments made by the Commissioners. And that is, first and foremost, can the Commission approve our proposal without engaging in rulemaking? And the answer we believe is clearly yes. We feel like the Commission has abundant ability to foresee on a case-specific basis, on a very targeted basis, to address that problem that Algonquin is seeking to help the electric distribution companies address and solve, and that is a gas-electric reliability and price volatility that we have talked about at this Commission for several years. Several initiatives have

been addressed; every time this issue comes up, the rest of the country says, "New England needs to get its act together, address it on a case-specific basis." And that is what we're seeking to try to do here today.

The other question is: If you can act, should you act? And we would say absolutely. There is a clear need for assistance for policy pronouncements from this Commission to help Algonquin, to help the Northeast, figure out how to move forward on resolving the capacity constraints that we all I believe, acknowledge exist. This proposal is a stand-alone proposal, but nevertheless I think we all recognize that it is part of the Access Northeast project. And we're not here to debate whether the Access Northeast project needs to be approved today; we believe it should be eventually, but it's not before the Commission. What is here today before the Commission is a proposal that would allow electric distribution companies to release capacity on a targeted basis for electric reliability reasons. And obviously to release it, they have the contractor capacity, and one avenue they're following is the Access Northeast project. However, the proposal I submitted enables them to contract for any capacity they acquire from Algonquin in any way, so it's broader than just Access Northeast.

The next couple slides -- and I'll breeze

through these quickly in light of the 15-minute restriction -- is just to restate the obvious: New England is using more natural gas, becomes more reliant on natural gas every day. The generators that are being built to serve the future needs of New England are gas-fired generation to a large extent. We project, ISO New England projects, that gas is going to comprise 60 percent of the generation in the very near future; it's 50 percent today. That is driving because of pipeline constraints extreme volatility in the gas prices, which you can see over these last two years, which results as ISO New England portrays it, as a tale of two seasons. The gas prices drive extremely high electric prices in the winter, such that ISO New England is an outlier in terms of gas prices compared to, say, MISO. In the summer when capacity constraints are less, I would point out we are running full-year-round on a west-east basis, so we really can't say the constraints are gone but the prices moderated. And that is totally because of the increased availability of capacity because the LDCs are not using it in any way. That's the fuel mix, who is supplying natural gas to the New England gas-fired generators. Algonquin, Maritimes -- and that's part of the two systems we're talking about -- both supply about 50 percent of the gas-fired generators. We do that with only about 3 percent of that generation covered by firm

contracts. That is a daunting number in our mind, over 50 percent of the electricity that we are responsible for supplying gas to is relying on secondary capacity release contracts. Another word for that is they're relying on interruptible contracts on a day-to-day basis. If they get it scheduled, it's firm. But every day they have to wonder whether it's going to be scheduled because it's interruptible until scheduled.

Here's our system-wide breakdown, the next couple graphs, of what our primary contracts are, what are secondary and what are interruptible, and this is for the total system. You can see that primary peaks in the winter and then declines. But the generation rely on secondary, there's only about 80,000 a day, dekatherms, of capacity committed to power generators, the rest of it is capacity release. So the problem we see is that the electric industry is relying on capacity that is not available during peak days during the winter. They're also taking advantage -- and not in a negative sense, all our customers take advantage -- of the flexibility that Algonquin provides. But it also is creating hourly concerns in terms of hourly flows both for the overall system and also on a generator basis. Essentially, we are using pipeline capacity that is committed to serve local distribution companies, designed to serve local distribution companies,

to serve a vast and growing demand for gas-fired generators. The reliability risk, in our view, is clear, the price concerns that the pipeline constraints create is clear. And that is what has driven us working with the electric distribution companies to attempt to come up with a solution. And this proposal is part of that solution in the sense that the electric distribution companies seek to acquire pipeline capacity and then on a targeted basis release it to generators for electric reliability. And to put that in context, and it was alluded to by the Commissioners at the start of the meeting, we have been talking about gas-electric issues and how to improve reliability for years. I actually have been talking about it since 2004. And we have focused on communication, and I think Algonquin has done everything possible to improve and enhance and have real-time information postings so that the status of our system is instantly known by the ISO New England to the extent possible. We meet with them frequently, we compare outages, we talk to them weekly, the communication is good. We have worked on scheduling and coordination. We do 42 nomination cycles for any given 24-hour gas day. We do that far in excess of any other pipeline, and increasingly 41 of those nominations, our scheduling response is no. You will see in the back of our slides a typical posting, we took it from this last winter,

which says, "No IT, no secondary out of path, no secondary in-path, primary only." And some version of that is issued every day on the basis of moving gas from the West to the East. So if you want to access cheaper gas supplies in the West from the Marcellus, from Pennsylvania, from Texas Eastern, you have to schedule it, you have to schedule it timely, and you have to do it on a firm contract, to even have a chance of getting gas. So we think that the low-hanging fruit has been fully addressed by Algonquin and, too, what remains is we have an infrastructure problem that needs be resolved, and this targeted release exemption is part of that solution. There's a slide on Access Northeast, we're not really talking about Access Northeast, but there's the slides.

So what are we proposing? We see the capacity release exemption that we're proposing as a continuation of Algonquin's ongoing efforts to improve flexibility, to be innovative in addressing the needs of the gas-electric harmonization communication coordination efforts. It is a pipeline-specific exemption, it is a narrow exemption designed to address EDC's releasing capacity on Algonquin. We're not asking for rulemaking for the entire industry, we're not asking for authorization for any other pipeline other than Algonquin. If other pipelines want to model this program, we would expect that they would come in to

the Commission and endeavor to convince the Commission that the public benefits outweigh any concerns. It permits a timely transfer of capacity. The EDCs are signing up for this capacity for the sole purpose of releasing capacity to generators when they need it. It is their belief, one that we happen to share, that by increasing the capacity, increasing the reliability of transportation services to power generators in New England, that it will generate tremendous benefits for New England and for their retail customers. That is why they are currently engaged in state proceedings seeking approval at the state level for these type of contracts. As part of that, they're asking their retail customers to be responsible for paying the cost. They need some assurance, they desire assurance, that they can in fact release these contracts to the entities for which they are requiring them for, which is generators. The existing exemptions under the Commission's current policy, we have tremendous amount of transactions that are currently released on a non-biddable basis under either prearranged transactions -- is really not sufficient. And they're not sufficient for two reasons: (1) They don't guarantee that the capacity gets to the electric generators, which is the primary goal of the EDC signing up for the contracts, that's why they're asking their retail customers to pay for the capacity; (2) The 31-day exemption

is a one-time exemption, it doesn't roll over. And we all have been in this room I think talking about generators wanting to find capacity at 2 o'clock in the morning from somebody. And I would hate to think that there is a capacity that's available that would keep the lights on that is not releasable because it was released two weeks ago to keep the lights on, but it's not releasable now without going through bidding, which under the current rules cannot happen until tomorrow morning. So we cannot do short-term releases. Long-term, it really boils down to the desire of the EDCs to be able to do targeted releases to the generation for reliability and price concerns. It's a priority of the EDCs to do this for the exemption of -- the mechanism under which the state EDCs will be doing this and the state programs will be discussed later. But it has been patterned after what has been approved for LDCs. In other words, the Commission found a public interest to promote in terms of the LDCs, it was retail and bundling. In this case we would submit the interest of electric reliability and price volatility. They permitted the LDCs to do this, to have prearranged releases, to the extent they were operating under state-approved plans. That's exactly what we're proposing here for the EDCs. If the EDCs have a state-approved plan, they would be treated as prearranged releases and released.

To the extent that parties claim that there are other solutions out there that solve or address the problems, Algonquin would admit that we have been trying to solve this problem in a multitude of ways. I mean, we are one of the few pipelines that have taken advantage of the Commission's contract policy of permitting multiple shippers to sign up under one contract. That was an effort to acknowledge that signing up for pipeline capacity by any one generator can be a very risky proposition. We filed that shortly after the Commission announced it was open to that idea. We have not received any inquiries from that. The truth is: Generators are very challenged in signing up for pipeline capacity, and that goes to the rules under which they operate on the electric side; that is the reality. We are not seeing generators sign up for firm pipeline capacity; we've held multiple open seasons and it has not materialized. Claims that the proposal is discriminatory I think misses the primary purpose of this. We would submit it's not undue discrimination for EDCs to be able to release capacity for the targeted purpose for which they acquired it, that is the basis on which the LDCs are releasing gas under retail programs essentially, is they have this capacity, it's for the benefit of the retail customers to promote the objective, unbundling, they're getting a targeted release. We believe a similar thought

process leads to a conclusion that is not unduly discriminatory to permit EDCs to release the capacity. It will be subject to scrutiny at the state level, the manner and method of that release is not solely the discriminatory decision-making of the EDCs but rather will be subject to the states. And we think the Commission can and should support such a program.

To the extent that the parties believe this is an effort to suppress prices -- and when they say that, that's usually a bad thing. It is an effort to lower prices, it is an effort to remove a price constraint caused by lack of pipeline capacity. We think that is a good thing, it is not an interference with the market. The market is working very inefficiently now we believe because of the price constraints, because of the capacity constraints. And so rather than seeing this as a bad thing, we think it is in fact a good thing to remove capacity constraints to permit the market to operate as efficiently as possible.

In terms of comments that this is premature, we would urge the Commission that, now, the arguments about whether proposals to fix the gas-electric infrastructure problems in New England are premature are being made both at the state level and at federal, sometimes by the same parties, which leaves you to believe they don't want a

resolution of the issue at all. But the states are currently looking at proposals from the EDCs in which the capacity release exemption is part of the proposal that has been submitted for the state to review, and the response at the state level is, "Well, FERC hasn't approved this. You can't approve this because FERC hasn't approved it." And we see some of the same arguments in reverse up here. We're not asking for approval of Access Northeast, but we do believe that this concept, this targeted release, if it is acceptable to the Commission, a timely issuance of an order so indicating will go a long way to provide the necessary guidance to the region on how to proceed. If this is not acceptable to the Commission or to the Staff, what is? Because we're open to ideas.

And I'm sure I've run out of time by now, so I will leave that at that, urging the Commission guidance here.

MS. FERNANDEZ: Thanks, Richard.

And now we're going to accept any questions or comments for Richard. And I'd like to point out that there's a standing mic to my right, if the audience members have any questions or comments as well. And please introduce yourself and who you're with before you speak. Thank you.

Commissioner Kelleher.

MR. KELLEHER: Joe Kelleher with NextEra Energy. And I had a question for Richard, one of two questions for Richard, that lend themselves to pretty succinct answers I think. But the first is a question that Commissioner LaFleur raised, which is need. In the Mass DPU proceedings, Eversource has said that this waiver is actually not needed, that the price suppression would be more effective with the waiver, I think they call it public benefits, but the price suppression would be greater with the waiver, but that the program of the price suppression, there would be a lower level that would be less effective but it's not needed. But here Algonquin is saying it is needed, so it seems like it can't be needed at FERC and not needed at state level. So I'm trying to understand the discrepancy.

One reason for the discrepancy might be, one theory, is that in the course of it negotiating the contracts the EDC's actually did believe it was necessary and that Algonquin is bound to file. And so when Algonquin says it's needed, they're really saying "We're contractually obligated to pursue the waiver." But since over time the EDC's have changed their position and they've concluded it's not needed.

So I guess the question is: Richard, can you explain the discrepancy between what Eversource is saying,

Mass DPU at the state level is not needed and what you're saying today, that it is?

MR. KRUSE: Well, I will allow the EDC's to speak for themselves; we have representatives on this panel. But in terms of Algonquin's perspective, it was requested by the EDC's. We see the wisdom of the targeted release and the purpose of it. It is my understanding, at least in Connecticut, the RMP that is contemplated in Connecticut does require such a targeted release. So in Massachusetts the EDC's very well may feel it's not currently being required at the state level. But from a regional standpoint, it is clear to me that there are some state agencies that see a lot of value in this. So we're targeting in seeking Commission approval to the extent we can create what is very much a regional solution and is going to require all of the states to participate.

MR. KELLEHER: Thank you for that. I just think it's important for the Commission's point of view -- I'm going to try to channel what the Commission is going to think about this -- it is important to see whether this is something that would be nice to have or something that is actually necessary.

The other question is just the program itself, the state electric reliability program is not defined in your filing. And to a suspicious mind is seems like any

program that any state asserts would somehow advance reliability, would fall under the gambit of its program. So if so, this waiver is very different than the waivers that the Commission has granted in the past when the Commission actually knew what it was approving when it was approving it.

Here the Commission would be writing, I think, a blank check to the states to say "Any program you stick a 'reliability' label on would be permitted." So I think the Commission would actually be approving a pig in a poke. Will you be providing more of a definition of what this program means or is the definition I proposed, really the absence of one, of what the Commission is supposed to rely on? And that's also for Richard.

MR. KRUSE: Well, we have Mr. Daly on this panel, I think he's going to talk a little bit about the structure of the state program that is being proposed. I would make the observation that the LDC exemption, the LDC waiver, does not require that the states bring their programs back to FERC in order to get approval of them prior to taking advantage of it. We have attempted to lay out our vision of how these programs would work. It is very much an ongoing process.

If there are guidelines that the Commission would like to put on what a state program would look like,

we would welcome that from an Algonquin perspective. We are really trying not to get caught in a catch 22 process in which we cannot make progress at any venue because some other key participant in it has not weighed in and expressed their views on the proposals that were created. So if the Commission want to put restrictions or feels like it needs to on what the program looks like, we're open to those. We do think you can creatively rely on the LDCs based on our description of the programs to come up with programs that work for the region. Certainly, there will be active discussions of that at the state level.

MR. KELLEHER: Can I interpret that answer as saying that you don't propose to define the term and that the Commission's invited to define it for you?

MR. KRUSE: Well, I can't really define it better than what we have in our filing. Proposals have been made, I can describe what, or have people that are familiar with that, describe what they're proposing at the state level. But in terms of contemplating what every state in New England is going to approve, I think we'll have to wait and see, unless the Commission wants to lay out some guidelines to begin with.

MR. KELLEHER: I have one more short one, please. You argue that this waiver is needed to promote the expansion capacity but the waiver would extend the

existing capacity. And I didn't see in your filing really an explanation why you propose preferential release not just for the expansion capacity but all for existing capacity.

MR. KRUSE: Well, it's the similar logic, at least in our mind, if the EDC goes out and is acquiring capacity, whether it's acquiring existing capacity or is contracting for new capacity, it's doing that for a targeted purpose which is to release it to generation, to increase the reliability of electric generation. And if they do that pursuant to a state program, presumably they're asking their retail customers to agree to be there, be part of that cost recovery mechanism for them. And it makes sense in our view to make sure that the capacity gets to the user, in this case the electric generator, that is the designated beneficiary of the capacity in the first place.

MR. KELLEHER: Thank you very much.

MS. FERNANDEZ: Mr. Daly, did you still have a comment or question?

MR. DALY: I was going to comment on the earlier question in terms of capacity release and why is it that we're targeting electric generation for this capacity release. The context of the discussions and the answers that were given that state level that were referred to are

that when we engaged with our utilities commissions, and I like to describe a little bit of that in my presentation, the EDC's entering into contracts on behalf of their customers incurring costs, and then asking those customers to pay for natural gas transportation, it seems there was a disconnect. If the charges to customers didn't end up with the benefits to electric customers, so by releasing the capacity directly to electric generators who would use that capacity to transport gas, and thereby lower the cost of electricity and increase reliability, those benefits were going back to retail electric customers, and that we thought the connection, a clear line of sight between the cost causation and the benefits, was necessary. That's why we included this as part of the program.

MS. FERNANDEZ: Mr. Brennan?

MR. BRENNAN: Yeah, I just wanted to emphasize how important the release is to the states and to National Grid. And I think, as James said, there's an argument that if we didn't have this exemption and the ability to target the release, you'd still get most of the benefits through the normal action of the market. But given that we're asking customers to commit to support these pipelines to address these reliability pricing concerns, the real way to ensure that it is always available, especially at those times when it's most needed, is through this ability to

allow us to target that release so it's used as needed.

And that's been very critical to at least some of the states, which is meant from the start, they're concerned that even if they accept the arguments that the market will work on its own, that in order to really be sure that the customers were receiving the benefit at all times, the one way to guarantee that load is targeted released to be able to ensure at all times on the coldest period when we have had several days of cold snaps, the capacity hasn't been released or taken up by another market participant and hopefully not used to address the reliability and pricing concerns that would be real at that point. So it is a real requirement for us, and I think, many of the states in New England to have this approved at FERC.

MS. FERNANDEZ: Thanks.

MS. LAZURE: Helen Lazure. We submitted some comments and some questions on the proposal. So my question now is specifically about regional market efficiency. Just whether you considered when certain entities get exemption bidding requirements, what if another entity is willing to pay more? And so how does that impact the efficiency of the markets on a more regional level of New England for example?

MR. KRUSE: Well, we have looked at the amount

of capacity that is really released on a good will basis. And the vast majority of that is actually prearranged. And that is something that has been, I think, sustainable in the marketplace because of the number of different capacity holders. In other words, you can almost get the same capacity from one primary shipper as you can from the next one, and then use secondary to get it there so that you can be in the marketplace continually on a prearranged basis to a certain extent. That is going to be more challenging and potentially in some cases impossible to do in the context of some of the contracts that we're contemplating in that it is very specific capacity, it is capacity that we anticipate will be operated on a regional basis.

And if you come in and use that capacity from point A to your power plant on one capacity prearranged basis, when you come back the next time it's going to be the same path and from the same capacity holder. So that's going to be something that would run a 31 -day requirement. So we don't see a real impact on the market dynamics, the vast majority of capacity is negotiated bilaterally on a prearranged basis and we don't see that changing.

MS. LAZURE: Thank you.

MS. FERNANDEZ: Staff, do you have any questions?

MR. GOLDENBERG: Yes, Richard, I have a couple

of questions. I think you mentioned that this 80,000 firm capacity that is going to generators today as primary firm?

MR. KRUSE: Yes.

MR. GOLDENBERG: Is that more or less than it was before the states had retail access on the electric side?

MR. KRUSE: I can't give you a precise number there, Michael. There's less capacity committed to power generation today than there was in 2004, I can tell you that. So if we have see a trend, it has been downward, not upward in terms of capacity holder. But tying it to the LDC program, I would have to go back and check.

MR. GOLDENBERG: You also, I think, mentioned, or you cited to an operational flow order that you had in the back of your presentation, that you said that is sort of representative of the winter where there is a restriction on secondary, as well as interruptible transportation. During those periods, are there generators operating in the ISO New England area, and if so, how are they getting their gas?

MR. KRUSE: Yes, there are generators operating, and they are getting it on the basis of holding secondary contracts or moving gas from alternate sources from the East. We have inputs coming into Algonquin on the East and from several different pipelines. What you do see is that

under peak day conditions, though, there is a significant percentage of the gas-fired generators not able to run and alternate reliability measures are being adopted by the ISO New England to assure electric reliability. Dual fuel is an example; turning on the old generators is one. So you get less than an environmental optimal generation mix. But the ISO New England has been able to keep the lights on at a cost, and it shows up in the electric prices.

MR. GOLDENBERG: Are the prices on the east of your system, the natural gas prices, higher than they are on the west in general?

MR. KRUSE: Well, I think as the pipeline constraints exist we see a flare-up in citygate prices for Algonquin across board. So the spot prices are high across board. It's those higher prices that incentivize some of the other market participants to bring gas in on the east end of the system.

MR. GOLDENBERG: You also mentioned, I think, in your presentation a short-term release at 2:00 a.m. in the morning or a nonstandard time where bidding wouldn't be permitted under the Commission regulations. Do you get a lot of those releases today? And if so, do you have the numbers of those short-term releases?

MR. KRUSE: Well, prearranged releases can come in at any time and will be implemented as soon as the

system is activated. So it is possible to do a capacity release at 1:00 in the morning and we have the gas flow at 2:00, if it's non-biddable. If it's biddable, that capacity release would have to wait until the bidding period, that is the next morning. So we'd miss that window of getting gas at night. As I've said, most of our capacity to release transactions, currently 80 percent or more is prearranged non-biddable.

MR. GOLDENBERG: Of those prearranged non-biddable releases, do you have any idea of the number that occur at 1:00 a.m., 2:00 a.m. at some non-biddable time, or are they mostly daily releases, monthly releases?

MR. KRUSE: I don't have a specific number. But what we're talking about is the one-off situation almost. Because it's an unexpected situation, the power plant needs to run at 2:00, we have no capacity, he has no gas, and ISO New England I know has been up here complaining "Where do they buy the gas? How do they get the capacity?" And on our system at least, if you have the capacity you can nominate, so you have a chance at getting it. If it's required to be biddable, if you don't have the capacity you're just out of luck. So most nominations, most businesses done on the day-ahead business, I grant you that. But the crisis will be at 1:00 in the morning where some power plant that is not holding capacity is asked to

run.

MR. GOLDENBERG: One other question I had: Under your proposal, if an electric distribution company obtained release capacity, would the bidding exemption apply to a rerelease by that electric distribution company or is it restricted to only primary capacity required by the EDC?

MR. KRUSE: I would say it's not restricted to the primary capacity system. If they acquired it for capacity releases and they had a state-approved program, they could redirect it on a targeted basis.

MR. GOLDENBERG: Thank you. I don't have any further questions.

MS. FERNANDEZ: We have someone in the audience.

MR. FOSSUM: I may be technically challenged. Actually, do these in the opposite order. I got a follow-up question to the question that was just asked. Once the capacity is allocated to the EDCs --

MS. FERNANDEZ: Did you introduce yourself?

MR. FOSSUM: I'm sorry, I skipped that step. I got the mic working, but I forgot to introduce myself. Drew Fossum with Tenaska Marketing Ventures, and our primary interest is ensuring the efficiency of the overall regional gas market and the secondary market.

So once the capacity is allocated to the EDCs,

and I guess the question, Richard, is: Is the expectation that the full capacity of the Access Northeast project will be allocated out to EDC's regionally, all 900,000?

MR. KRUSE: The premise of the Access Northeast is that we're building a 900,000-a-day expansion that would be committed to the EDCs.

MR. FOSSUM: Okay, let's assume that just for now just for simplicity. So once that capacity has been allocated out to the EDCs, the EDCs through this yet to be designed state mechanism will in turn release that capacity to chosen generators who will use that capacity to move gas to their power plants. Right? That's a question Commissioner Kelleher asked about how that process works, and that allocation mechanism has not been defined yet. Right?

MR. KRUSE: That allocation methodology is in the process of being defined, and the application is going to be pending in Massachusetts.

MR. FOSSUM: Thank you. I'm building up to the real question here, which is this question: Once that allocation mechanism has done its thing and the 900,000 in capacity is allocated to the EDCs and then released by the EDCs to the generators, is that capacity in the hands of the generators eligible to be rereleased into the secondary market?

MR. KRUSE: Well, as contemplated by the tariff filing, it would not be. In other words, the EDC's are releasing it on a targeted basis to guarantee that it's being used for electric reliability purposes. To the extent that it's not being used, it would be recallable by the EDCs.

MR. FOSSUM: Richard, I know your filing asks for the exemption from the posting of bidding rules that would permit that first allocation to occur from the EDCs to the generators, but I don't recall that you asked for a separate exemption from the capacity release rules to provide that that capacity once in the hands of the generators cannot be rereleased. Did I miss that? Does the filing cover that? Or is that done at the state level through some sort of a prescriptive rule?

MR. KRUSE: Well, I think if you look at the tariff language, at least it was our intent to be clear that it's a release on a targeted basis to the generators, when the replacement shipper is required to provide electricity to the market serving the electric distribution. So the intent was really that the EDCs could release the capacity one of two ways: They could either release it to electric generation to generate electricity on a targeted basis; and then to the extent that they had no need or didn't see a need for targeted releases, they

would release that capacity pursuant to the current Commission rules, which is the ones that apply to all other shippers.

MR. FOSSUM: So this capacity, Algonquin's view is that this capacity, once in the hand of the generators, can enter the secondary market but through normal vanilla tariff capacity releases. Did I hear you right?

MR. KRUSE: I don't believe so.

MR. FOSSUM: It can't. Well, I'll shut up about it.

MR. KRUSE: Our intent was if it's released to the generators they will use it to generate electricity. That's the only reason they get the capacity. If the EDCs have a desire or need to release the capacity for any other reason than electric reliability, they would have to comply with the existing capacity release rules, including the bidding requirements.

MR. FOSSUM: Our company has built a lot of generation, and I know there's varying load factors based on units. But peakers generate less than 20 percent load factor big combined cycle units 50, 60, 70 percent load factor, but they don't run all the time. Right? So there's going to be a lot of times when this capacity, whether held by the generators or somehow gets back into the hands the EDCs, isn't being used to haul gas to these

power plants. So if that capacity cannot rereleased to anyone else, it essentially is unusable by the market? Is that the lay of the land here?

MR. KRUSE: No, I wouldn't agree with that characterization. I think there's a -- and certainly some of the EDCs may want to address this -- but as stated, there is a desire to make sure that if the EDCs are going to ask this retail customers to allow them to buy this capacity in the first place in order to support reliability, they need -- they want some assurance that that capacity will be released to generators for the purpose of generating electricity. They're not releasing it to generators for them to turn around and release it into the gas market and not generate electricity.

MR. FOSSUM: But when they wouldn't be running anyway, they can't release it into the gas market for someone else to use I think is what I'm hearing here?

MR. KRUSE: If you want that capacity under those terms, you should be talking to the EDCs about releasing the capacity, not for electric reliability, but for general market gas-electric purposes. And then you can get it and do with it what you want.

MR. FOSSUM: Thank you, Richard.

MS. FERNANDEZ: Mr. Adams and Mr. McCauley.

MR. ADAMS: Just real quickly. Capacity, just

generally speaking, is one of the legs of the puzzle that generators like Calpine and Epsilon and ENGIE use to actually fire a plant. In the context of Mr. Kruse's example of a generator coming on at 2:00 and this proposal will make capacity available to that generator, that doesn't mean gas shows up at the plant. We have to go out and buy gas into that capacity.

So, Mr. Kruse, can you tell me what sources of gas will be available to generators when you assign us this capacity?

MR. KRUSE: That's going to be dictated by what capacity you acquire.

MR. ADAMS: Well, if we acquire capacity that is part of this program, I think that's a pretty clear-cut question.

MR. KRUSE: I mean, if you want to talk about what Access Northeast does, it moves gas on a west-east basis, about 500 a day, from liquid interconnect points with Millenium and Ramapo and Iroquois to the east with capacity that is constructed to assure delivery at each of the power generators currently attached to Algonquin's system. It also envisions an LNG storage facility that would liquefy the gas and make it available during the peak days for an additional 400, and that's how you get to the 900. On any given day, if a generator is wanting to move

gas from the west to the east, it will have 500 a day. It can call on the LNG capabilities. The service envisions, several creative features including non-ratable tanks from the LNG facility, as well as basically the ability to take deliveries without nominating a source of supply.

One of the problems we're increasingly seeing on Algonquin -- and our flexibility is getting stretched further and further every day, we see that by the increased numbers of LFOs we're issuing -- is that the system is operating at full capability. And at times we will see generators come on without nominations. And we address that issue through the Access Northeast by giving them basically a two-hour grace period to go find gas. We are seeing situations where generators come on without a nom and so we don't know where they're getting their gas yet. And when we ask, we usually get begged for one-hour forgiveness at least. And we do, I think, a pretty good job for trying to accommodate the realities of the gas-electric interface. But there are limits to what the system can do.

That's the base of why we feel like a different capacity that needs to be committed to support the electric generation market. We're not building capacity for every plant to run all the time. We're building it at a significant percentage but not for all of it. So you'll

have more choices in terms of where your gas comes from under Access Northeast than you will without it. Again, where that gas comes from ultimately is the shippers' responsibility to find it.

MS. FERNANDEZ: Mr. McCauley?

MR. McCAULEY: Good morning. I'd like to start off by saying that collectively National Grid and Eversource put together, what we filed in Massachusetts and the National Grid will at some point have EDCs with Rhode Island, and electric reliability service program, and that was first mentioned by Richard. And in there we lay out specifically a schedule for when we would make capacity available to the generators and it would be done on various terms, whether it be yearly, seasonally, monthly, weekly, or even daily, to make it available to a market and specifically to the generators again for reliability, to make it available for them to generate electricity. And if that capacity is not released out to the market to the generators, that ultimately the EDCs through a, right now, planned capacity manager would make that capacity available through bundled sales to market participants. So it would be ultimately available to both generators and the rest of the market participants. So it can be, in the end if the capacity is not needed for the generators, will be available to the market. So ultimately there will be a

convergence of prices that maybe the generators are willing to pay and what the rest of the market participants are willing to pay. So I think that addresses some of the questions.

The question as far as for electric generators in the capacity that they would get under their capacity release, we've put a clause in our electric reliability service program that it could be recallable by the EDCs, again for reliability reasons if the generators are not using it to generate electricity, that it would be up to the EDCs to decide whether it was a reliability issue from a generation standpoint to then recall the capacity and then make it back-available to other generators. It doesn't necessarily mean that we have to or will recall it, you just need to have that assurance that the capacity is available for any other generator in the New England region that might -- that could use it to produce electricity. So I think that addresses a lot of the questions that were asked before.

MR. HOWE: Richard, on the question of rereleases by electric generators, I didn't see anything in your proposed tariff language that would prohibit electric generators from rereleasing pursuant to the ordinary rules. I understand that the state program proposal has a prohibition, but if some state wanted to permit rereleases,

is there anything in your tariff language that would prohibit the state from doing that?

MR. KRUSE: Well, if there is, that is certainly something that we'd be willing to tweak. The reason I was saying there was is that the requirement on the targeted release was that it was for electric reliability purposes only, that that is where I got the statement there, if you're not going to use it for electric reliability you've acquired the capacity in a way that's inconsistent with the waiver exemption that we've asked for. But if programs are evolving or changing, we're open to that, and to accommodate that.

MR. HOWE: But the tariff language itself seems to just be an exemption from bidding as opposed to any kind of prohibition on different types of releases. This may be a question more for National Grid and Eversource, but would the capacity manager have the ability for a one-year release to an electric generator and there's times when the electric generator isn't using it, could the capacity manager recall in order to make a release to the market, general natural gas market, or recall for the ability to send the capacity off to another electric generator?

MR. BRENNAN: I think that was the point the Steve had made, he said details of that electric reliability service and the overline does allow that to be

recalled if it's not being used as intended to address the reliability concerns of the energy market. So to the extent that when it's the generator's not, finds out, regardless of purchase of the year-head or day-ahead, at some point, it's not going to be dispatched, it's not going to used as a division to provide electricity. Then it could be recalled, but at the point depending on the details of the time and the need for other generators to employ that capacity, it could be targeted back to electric generators. If on the other hand it's not needed to any generation to be released to secondary market by the capacity manager.

MR. HOWE: And finally I have a request really for Algonquin in its comments to have more detail or as detailed information as you can give us as to prior to each state restructuring program back in the late 1990's, what percentage of gas-fired generation in New England was actually served by firm contracts? And then to the extent those firm contracts in state restructuring got transferred to independent generators, what happened to it thereafter? And in the end I'm interested in knowing to what extent those much higher percentage of gas-fired generations certified firm contracts prior to the state restructuring programs than after?

MR. KRUSE: Well, the vast majority of the

contracts that were transferred to the generators during restructuring have unfortunately probably been rejected or terminated, and they were rejected in bankruptcy. But we'll provide that information.

MS. FERNANDEZ: Mr. Fossum.

MR. FOSSUM: I'd like to follow up again if this is still on. I have a follow-up question to a question that Richard Howe just asked, and I think clarified something I guess I read in the filing, but it hadn't clicked. We've heard that once the capacity is released to the generators, the generators cannot release it into the secondary market themselves. It's not in the tariff language that Algonquin filed, but that's a restriction in the state program. Have I heard that correctly? Assume that for a minute.

We also heard that the EDCs can recall that capacity when a generator is not using it, so once the capacity is released to a generator, if that generator is not using it on a particular day or hour, the EDC for reliability purposes -- that's the phrase we heard a couple of times -- can recall that capacity from generator 1 and then allocate it to generator 2 or 3 so that generator can use it to generate electricity. Is that correct?

What I don't think we heard is whether there's any way for either the generator by releasing it to the

secondary market directly or the EDC by recalling the capacity from the generator that wasn't otherwise using it and then putting that capacity by release into the secondary market, neither of those ways are available to get the capacity in this 900,000 Access Northeast project to anyone other than a generator. You can't get it to the gas LDC who needs it, you can't get it to an industrial that needs it. Once this 900,000 capacity is built in the hands of the EDC's benefit, the generators -- I'm hearing sort of a Hotel California problem, once it get in it can't get out -- it can't ever get back into the secondary market for use by anyone other than a generator. If I'm wrong, strike me out; and if I'm right, can we talk about whether that's something there might be some flexibility on?

MS. FERNANDEZ: Mr. McCauley.

MR. McCAULEY: Sure. Ultimately what you said is, I'll say, mostly true to the extent of the exception that ultimately we want, as EDCs, to have all this capacity used as much as possible. And our goal will be to get the capacity out to the market, whether it's through releases by the EDCs to the market and have it biddable, if the capacity is not being used, if there isn't this need for all of the generators. And ultimately it will be available to the market through bundled sales by the capacity manager out into the market itself, or it could be generators that

have the capacity and the EDCs do not need to recall it for reliability reasons.

MR. FOSSUM: Who is the capacity manager that would be making these bundled sales?

MR. McCAULEY: In a proposed, Eversource and National Grid have proposed that we would be using a capacity manager. It doesn't mean that all EDCs in the region will, but that we propose that we will have a capacity manager managing collectively the capacity that was contracted for by the National Grid and Eversource. So it would be a third-party capacity manager that we would contract with it to manage the assets for at least the National Grid and Eversource.

MR. FOSSUM: Okay, I'll stop here. But one of the things my colleague Tom Lockett will speak to later, from Tenaska, and I'll just mention now is, we'll be looking for assurances that these various steps in the process that we just learned about will be conducted on an open and transparent and non-discriminatory basis, much like posting a bidding operates under the current rules to assure nondiscriminatory allocation capacity. Each one of these steps, the initial allocation by the EDCs to generators, the flow of that capacity back into the secondary market, either through bundled sales like we just heard about or through recall from the EDCs and rereleased

back into the market, the filing is pretty sparse on how the what we believe to be currently very efficiently-operating secondary market will continue to operate efficiently in that respect. So this has been very helpful, but there's some steps we would like to hear some more clarification on. Thank you.

MS. FERNANDEZ: I think this would be a good time to turn to the EDC's joint presentation. And with that, we'll thank you, Richard. And I'd like to now introduce James Daly, Tim Brennan, and Stephen McCauley.

MR. DALY: Thank you very much. So the purpose of this presentation -- I'll do the first part of it and then hand it over to Tim Brennan for the second part -- the purpose is to give you some context from the EDC perspective as to how we entered into these contracts and the reasons behind why we're asking for this tariff change.

So starting on slide 2, so this started, just to put it into context, this started in 2013 when we got a letter from the New England governors supporting infrastructure development. So I think you'll appreciate New England has six states, it's difficult to get six states organized behind a single effort, so that's somewhat notable in itself. I won't read all of the text of the letter, but basically the New England governors directed their staff in order to envision -- calls the New England

State Committee on electricity. It's a small staff run by the governors of each state as they're involved in wholesale Electricity matters and energy matters generally. So they directed them to lead the regional effort, and we participated in that with a lot of other stakeholders.

So over a year, year and a half or so they solicited proposals from the marketplace to address this particular critical issue of gas generation, gas-fired capacity power generation, which was not yet in the region. They submit lots of different proposals, had a very open forum, a lot of the participants who are in the room here also participated in that.

So in looking at where that was going and recognizing there really weren't a lot of very solid options in the marketplace, we, Eversource along with National Grid and the United Illuminating decided we put together a proposal so that at least there was one workable proposal. The fundamental problem here is: Having strong credit rated entities contracting for capacity that would then cause the interstate pipelines to develop this. In other words, they'd put up a significant amount of dollars necessary to extend, to build these pipelines and they charged their customers. So it was a charge to the customers basically with high credit ratings, that if we came forward on behalf of our customers we could put a

solution in place.

So we made a proposal to NESCOE and out of that there were a number of proposals, but it was really the only one in our view that was going to actually solve the problem of the shortage in pipeline capacity. So we made that offer, as generally we would provide credit support on behalf of our customers because of the benefits; and I'll show you those benefits later. So that was about a two-year process.

So on slide 3, what developed -- so in that time frame states were addressing the issue of who would contract for natural gas, whether the EDCs could do it or not. And by the end of last year we had Massachusetts and a number of other states had taken action to make it clearer what electric distribution companies could do. So in October of last year National Grid and ourselves issued an RFP for infrastructure, for an increase in infrastructure to reduce the high cost of volatility of electricity in New England.

Some of the structural requirements that we put in that RFP had to be a regional scale. There were a lot of smaller solutions that could be implemented on their own that didn't need our involvement to do it. But it needed to be incremental gas, transportation capacity or gas infrastructure. We know what's out there in the

marketplace, the reutilization or repurpose of what's out there really wasn't going to affect reliability in the region. So incremental infrastructure was needed.

And what was lacking sorely was primary delivery to doing the power generators, so we wanted firm delivery to the power plants and inter-station of the power plants. So in response to that RFP we got about 20 different proposals from all of the regional players. We put on the company websites and issued it to the players. I mean, we generally know who's active in the marketplace and market their proposals, there aren't any secret proposals out there, that people are constantly engaged in the marketplace. So we found what proposals were out there and we went through a process, so it was a competitive process to select Access Northeast, was selected by Eversource and National Grid.

So net customer benefits, long and short, is about one billion dollars per year; I'll show you more on the cost of that. 900,000 dekatherms which involved both transportation on pipeline and natural gas, and it would access most of the power plants in New England, 50 percent of the power plants in New England, flexible with no notice service.

So power generation has been asking for a service like no notice service, no limited service, you can

actually fire up your power plant for two hours and be running before you need to notify the pipeline of what your nominations are. So no notice service is supported by the LNG within the region and provides for a lot of flexibility. And at the end of the pipelines we have a lot loss options in a lot of other parts of the country. So specifically designed for power generation.

So that resulted in the present agreement which we had filed with state regulators. Eversource filed in Massachusetts and New Hampshire and National Grid has filed in Massachusetts and will soon come along with Rhode Island. And indeed there are other proceedings going on in Maine, shortly there will be -- there's a process going on in Connecticut, we expect to see an RFP for this type of capacity in Connecticut shortly as well.

So I won't go through all of the -- on slide 4, I have a synopsis of what all of the states are doing. I won't go through all of the language of it except to say that five out of six of the New England states -- Vermont is not connected to the pipeline flows, but the rest of New England is. So they're not actively participating, but are generally supportive of gas-fired generating capacity.

In terms of looking at some of the numbers, I think this is what -- this will give you a picture of what distinguishes New England from the rest of the country;

everybody knows we have the highest electricity prices in the continental U.S. in New England. And this is a calculation of -- this is basically the clearing prices in ISO New England in the period from December through March for each year. So this is -- this drives the clearing prices in ISO New England, this is the cost of gas in dollars per dekatherm. So the read bars, you will see, it's quite volatile. So in the winters of '12-'13, '13-'14 and '14-'15, you can see the red bars had dislocated from the rest of the country considerably. So I'm showing you the -- what results in the electricity prices are coming up in another slide.

But we also added here the effective heating degree days, percentage to actual 30-year average on the bottom line. So you can see when it's cold in New England, in other words when there's very high effective heating degree days, the volatility breaks out, so we get these very high spikes in electricity prices in New England.

And then in a very mild winter, like last winter, which was 70 percent lower than normal on a temperature basis, you can see it falls back closer to what the rest of the country is. But that was an extremely mild weather conditions, some of the warmest in recorded history in New England, but still had volatility. So even under very optimistic, very mild conditions, New England still

has issues on its prices, its gas prices driven by shortages.

These bars show the actual billions of dollars that it cost New England's electric ratepayers depending on the winter. Again, this is December through March. So you can see on maybe more of an average-type winter New England consumers need to spend about $3 billion, but then in a very cold winter it can go up a another $3 billion as we've experienced and then fall back again in milder winters.

So this is a very high-cost driver, so it affects how our customers look at New England as a marketplace for expanding, the industry forums where they talk about having to relocate the manufacturing process out of New England. We've had paper mills shut down and send their workers home in January because of shortage of natural gas. So these are a real and very significant drivers for our economy. And high prices aren't bad for everybody of course, there are people who are beneficiaries of these high prices, and I'm sure some of them are here today. And you know, we understand that they like the high revenues. But our customers are paying extraordinarily high prices and need relief.

So the question is: What are the other options? And as I started, there aren't a lot of other options for our customers except to move off electricity, which

obviously in the modern world isn't that palatable. And there are people who are more for renewable energy, and we said, "Fine, let's have renewable energy as well, but we need natural gas to back up renewable energy in the form of New England Solar. We can't continue to expand our gas-fired generation on a firm basis without gas infrastructure to support, it just isn't feasible." During times when the sun isn't there, when the wind isn't blowing, we need firm capacity.

So in summary of this one, so those numbers and other numbers we've looked at say what are the benefits of it. We've hired ICF to do an analysis of the benefits of it, adding gas transportation. National Grid hired Black & Veatch, Independent, nationally-recognized consultants. So both studies determined that ANE will generate significant savings for our customers, will increase reliability to the region. So under normal weather conditions, as I said, it's about a billion dollars a year, we get severe weather or, indeed, if we had a nuclear shutdown that number can go to about $2.6 billion per year. So very significant numbers during the solicitation for these investments for both the cost of electricity and reliability.

So that's more the context of how we got here and why it's important to us. I'll hand it over to Tim Brennan at this point to take us through the rest of this.

Thank you.

MR. BRENNAN: Thank you. And I know at least John wanted to talk, so I will try to quickly move through this and we'll have some time for questions. This next slide, slide 8, is just a summary, I think, of what we've been talking about. Clearly, we're trying to get this targeted release to ensure the capacity can be used, what we're asking for the benefit of the customers who are asking to support it, and align with that to address the reliability and pricing concerns. We talked about how, obviously, the states this is important to will be involved in setting up the fine details of the electric reliability program. As we clarified in some of the questioning clearly we're not required by the generators to release CPUs to produce electricity. I think it's in everyone's benefit and advantage to make sure that capacity is released either to other generators who might need it and ultimately to secondary market. No one is advantaged by simply use -- holding onto that capacity when it's not being used to meet its intended need and assure the reliability of electricity market.

I'll move onto the next few slides, which I know one of the reasons for this technical conference or perhaps -- was to address the concerns that we're seeing and raised in a lot of protest and comments. We had gone through a

lot of those protests and comments and identified some of those main concerns. The first one covered on this slide is a concern that we're somehow removing .9 BCF from the secondary market, distorting pricing and really causing some problems there. I think the thing to remember -- and I think John or someone brought up I think a reminder that this is additional capacity we're talking about here -- clearly, this is EDC capacity for reliability program. So we're talking about, first, that additional capacity being allowed to be targeted, and then when not used being available to the secondary market. So really it can only possibly add to the secondary market and availability capacity in that secondary market. It's not disrupting by removing existing capacity from the secondary market.

Another concern that we have heard many times is that this is just simply an effort to artificially lower gas prices and gas transportation prices, and suppressing wholesale markets. We've talked quite a bit, it's clear this is an effort required by the EDCs, the generators have been unwilling or unable to ensure adequate infrastructure. So for reliability we're adding infrastructure. Yes, the effect will also be to lower the prices and extreme volatility that we've seen, as James mentioned, over the past several winters. But there's certainly nothing inadequate about ensuring adequate infrastructure, there's

nothing wrong with the result of greater reliability and reduced price volatility for customers.

Another concern that was brought out in many of the comments was that at least three ANE projects and this exemption here that would issue, it's going to create haves and have-nots in favoring certain generators over another, and that was inappropriate and disruptive. The first thing to remember is that the capacity to be released will ultimately be available to all generators able to produce electricity in New England. Now, some may be located close to the pipeline, the aggregation areas have an easier time of making use of that release. But there's no prohibition against other generators if they've had other arrangements to get from those areas to take that capacity and use it as they may to generate electricity. And, yes, while certain generators will obviously have a greater ability at times given their particular locations to use it, this is understandable about any investment and infrastructure. And a good analogy and one to think of is is when we build infrastructure on a transmission system, the system decides what transmission is needed, where is it inadequate, and what is cost-effective, whether it's reliability or economics for example under the New England tariff. And when you build that infrastructure that's found to be needed for reliability and cost-effective for customers,

there's going to be some generators on one side of the transmission restraint versus others on the other side who would be advantaged or disadvantaged, in the short term at least, by higher prices in one zone, lower prices in another zone. Some examples to think specific to New England, if we were to relieve transmission from Maine, Maine generators would be able to be dispatched more and flow out of Maine and serve the needs of the rest of the system; if we were to relieve the constraints into NEMA, Boston, where again, some units in Boston might have their prices lowered, but other resources outside of Boston, who were dispatched down because they couldn't get into Boston, would now have the advantage of that infracture. That's just simply due to where they had chosen to locate their investments and the fact that infrastructure that was found to be cost-effective, the need for reliability happened to be closer and advantaged them more than others, at least in the short term. That's just the natural effect of building infracture.

Another concern is that these places could be perceived to limit a generator-preferential capacity to only selling to the market serving electric distribution company, and I think that was some misinterpretation of the language we had chosen. When we were talking about the market serving electric distribution company, at least I

can speak for I think Eversource and National Grid, we're talking about the entire New England wholesale market. It was not intended to say that this capacity only has to be to generators dispatching for instance in the national mass-electric distribution company area of National Grid. So this was simply -- I think this concern expressed by some participants was just a misinterpretation of the language used, you know, we want this to be available to the entire wholesale New England market from which we all draw our power -- to go to the security-constrained economic dispatch, it's not generated by generator or distribution company but by a distribution company.

And so this, again, is a concern that was raised, that the proposal would insulate electric generation from the true prices of interstate pipeline capacity and that it was a subsidy to electric generators. And I think, I want to emphasize again, that this is needed infrastructure and there's nothing disruptive to the markets or a sign of undue discrimination or preferential treatment by the EDCs trying to get adequate infrastructure for deliverability of gas to New England. If you consider other generators, they also have often -- are advantaged and like you might say subsidized by society paying for the infrastructure required to transport fuel to their facilities. If you take, for instance, Maine baseload

clients that require fuel to be delivered by ships, society and taxpayers fund intermodal facilities, ports, shipping channels, to make sure that their ships can make it to the market. The generators are not responsible for paying for all of that infrastructure. Same with resources that get their fuel by use of ground transportation, highways, bridges, local roads, those are all taxpayer-funded, society-paid infrastructure that help the fuel get to the plant. So it's not a question of buying the fuel itself; we're simply here talking about making sure there's adequate delivery infrastructure, the same type of infrastructure that's funded and subsidized, if that's the word you want to use, for other resources, not just gas resources in New England.

And there's also a point that the winter reliability program, we saw some comments in the protest of COF between the winter reliability program, which is a transitional program going on right now in New England, until we get to the performance incentives and the enhanced incentives in the forward capacity market. But those two together will assure system reliability on a going-forward basis. And I think the best evidence that that's not true is if you continue to follow New England markets and see that the ISO New England still has concerns and -- in the words of the CEO Gordon van Welie who says, "The

fundamental challenges facing New England remain the same and the perspective has not changed. The system continues to be in a precarious system during extended periods of extreme cold. The region will continue to be in this position until the New England natural gas infrastructure is expanded to meet the demand for gas." And if you look just to last year at ISO 1, in any day that they were concerned that 4,200 megawatts of gas-fired generation could not get the gas if they were called on in certain circumstances.

We've talked a little bit about it, I'll -- quickly. This is similar to past exemptions, a lot of it is analogous in many ways; we're buying capacity systems we've had in the past -- for their gas customers, where if you're buying capacity for the LDC customers, were buying capacity for the benefit of EDC customers, we want to make sure that capacity, at least initially, can be targeted and used as desired before it's released to the rest of the market. It will be released in both cases that hangs under the LDC program, it will under the EDC electric reliability program. To the extent it's not used to need, and in many others it won't be, it will then be released to the secondary market.

So I think in conclusion, I think you've heard the arguments that we've made of why we think this is

important, it makes sense, it's nothing more than asking the customers -- the customers, to ensure that the capacity that they're supporting can be used to meet its primary need. To the extent it's not, it will be released and made available to the rest of the market. Thank you.

MS. FERNANDEZ: Thank you, Tim, Stephen, and James.

Now, we'll take questions. I think Commissioner LaFleur has a question.

COMMISSIONER LaFLEUR: Yes, I have a couple questions. It seems like the right people to ask it, although I'll take answers from anyone. And I'll ask my first two questions together because they're related. So to Tim's point that what the EDCs are doing is asking their customers to fund the development of needed infrastructure like a shipping channel or railroad or whatever, if you went forward and had the customers fund pipeline storage that you're looking at but didn't have the specific hardwired capacity release but that capacity that the pipelines enabled was released according to the normal FERC rules or some much more limited exemption, do you not think that customers would get the benefits of more reliability, lower cost, given the market dynamics you both describe? And then kind of a related question: Clearly you're trying to protect your electric customers from some risk by

hardwiring it this way. Can you articulate what that risk is and who you think should bear it if the electric company shouldn't? Those are hard questions, but this is a hard case.

MR. BRENNAN: I think I'll first get to the first point. I think as we talked earlier, there is an argument that the market itself will take care of it without this exemption. But as I talked earlier, I think many of the times that's likely to be true, but in order to really -- the real issue here is, you'll see from some of the charts as you follow others, is the real extreme point when you have significant cold or -- either prolonged over winter -- you've got over three or four days. And it will be a shame if in those days we see prices such as we saw a few winters ago where a generator and PJM in the same day could get to the one that's out of gas to generate electricity, could get gas to $3 dollars at $3 million BTU. In New England that day generators were buying from spot market at $36 a million Btu, for 10 times, due only to that infrastructure constraint. So an example of the concern that someone brought up in New England, we hear often in the public hearings, is, "Well, this gas is just going to be brought into New England and liquefied and sent around the world, so it will be no benefit to -- the customers." Well, clearly we would not want that to happen. And

whether you think it's likely or not, this could prevent that. If we get to the point where the LNG prices on the world now are like they were just a few years ago and there was a liquifaction facility that could enter into our initial release, buy up all of the capacity because it was more advantageous for them to sell it off, that'd really be the worse-case scenario where we would wish we had this ability to assert -- for the generators who would need it at that same time. That's not the result we want to get to, and I think we and the states and our customers would all be in a bad situation if that was allowed to happen. So let's make sure this is made available to satisfy its intent first. If it's not needed, then it can be made available to anyone else including someone who might want to liquify it and send it somewhere else.

MR. DALY: On the second issue, so in terms of who bears the risk for this, we as EDCs see this as very similar to the way we operate on the LDC side. The business model on the LDC side is that we contract with capacity, that's to benefit our customers. And the customers pay for that over the long term, it's the most efficient way to do it. So they're the beneficiaries of it. In terms of risk, the pipeline has taken on the risk of construction, they don't get paid until it goes into service. So people who have opposed -- bring up this --

they could get paid and not -- that's not the case -- requires them factually delivered, it's FERC-jurisdictional, the cost they can charge us. So it is regulated, they won't have to pay until it goes into service. But once it goes in service, we believe the customers should pay for the cost of it, assuming our retail regulators in the states approve that, and we're going through the process to determine whether that's -- so there are contested proceedings in the states, frankly underway, and utilities, commissions will make the determination as to whether it is in the customers' interest to make these charges. We as EDCs think that's where the costs should go because that's where the benefits should go, and it's very similar to the way we operate on the LDC side. We also say in response to criticism as to why are you doing this, you say show me a better alternative. Well, what is your alternative? And nobody has come up with one --

COMMISSIONER LaFLEUR: Tim, to your point, is this day -- this winter day of gas was 13 bucks in New England and 3 bucks in PJM --

MR. BRENNAN: Excuse me, it was actually 30.

COMMISSIONER LaFLEUR: Sorry, 30 bucks in New England and 3 bucks in PJM. Wouldn't the suppliers be motivated to sell gas in New England and the generators be

motivated to buy gas so they'd be taken? And if the real issue is not exporting it, have you considered just saying, "Hey, this can't be exported," but not all the other controls?

MR. BRENNAN: I think the issue is, without this infrastructure being built, we would continue to see these $30 and $3 days due to only the infrastructure constraint. So we need that infrastructure to be built so that the capacity and the load prices and the price have sufficient supplies to meet the demand.

COMMISSIONER LaFLEUR: I was going to ask why you need the release. But I would just ask one more question, and then I'll turn it over to staff. Have you parsed how much of the benefit that your customers are getting comes from the storage piece as opposed to the pipeline? Because this is the project you're bringing forward is kind of like a half-storage/half-pipeline I think? Or is that not a meaningful question? Because you've obviously figured out what your customers are getting.

MR. DALY: So we asked our ICF to model this particular program. So the benefits that we talk about a billion dollars a year are modeling the combinations. We modeled the project. We didn't model variations on the project. So what we're seeing is the pipeline capacity, if

we were to add all the pipeline capacity, for example, would increase the cost of the project. The LNG is more of the peaking nature, so it provides economics that are superior to, say, the $900,000 pipeline. So it was the optimization of that supply into the region, so we modeled that piece of infrastructure in addition to what's there already, and then translated that into the electric market and ran models that simulate the production in the electric market and came up with those numbers. But we didn't do variations on this, that's a lot of what if's, but we felt this was the best project by far that we evaluated as part of that competitive process.

COMMISSIONER LaFLEUR: Thank you.

MR. McCAULEY: I'd like to try and answer your question: Why the release? And I know we said this a couple of times similar to the ODC lines and the contract for capacity and they use it for their own use, and when they decide for reliability reasons, because it's not cold enough, that there's excess capacity, they make it available to the market. Thinking along the same lines, that's what will happen here.

Similarly, the EDC's are taking a risk in signing up for this capacity to generate electricity but is now having to go out into the market and we wanted it to go to the generators who are going to produce electricity, I

would say it would be comparable to saying that the LDC's need to sign up for this capacity and don't first fill it through their own use, go ahead and release it out to the market, and now as LDC's go back out and rebid for this capacity. Now you're competing with everyone.

We're purchasing the capacity on behalf of the LDC's to be first used by the LDC's, we're purchasing the capacity for the EDC's to be used first for the EDC's, and then it will be made available to the rest of the market just like it is today with the LDC's and the excess capacity. So that's where we were getting to as to why we need this -- it has to first go to the generators because that's the primary reason, to produce electricity.

MS. FERNANDEZ: I think Staff had a question and then I will come to the speakers and then go to the audience, okay. I actually had a question and then Michael has a question and Richard has a question, we have a lot of questions. My question was: I know that Richard had mentioned the concern here, one of the reasons for the exemption was sort of the 2:00 a.m. call and you can't wait until the morning to do the bid. But I know based on your proposal, at least from what I understand from what has been filed in Massachusetts, is that you currently anticipate daily, monthly, yearly releases and that as far as the daily is concerned that would be two days in advance

of delivery. So I'm not understanding, given sort of the new bidding deadlines after 809, why you need the exemption if you're just talking about a daily -- I know it's not going to be hourly in the middle of a night -- why you need the exemption from bidding because you can do prearranged deals provided that your generator matches the highest bid? Thank you.

MR. McCAULEY: I think what we're saying here is, in the market as to the question what happens at 2:00 a.m. from a release standpoint, because I don't think that's not possible to release capacity that's available. The release is for in the period that's well in advance that allows the generator-purchased gas to generate electricity. In the middle of the night, the asset would still be available, and this is where either the capacity manager or if an EDC decides to retain the capacity by themselves to market it themselves, they would then make the asset on the short term notice available to the generators.

MS. FERNANDEZ: Then why do you need the bidding exemption? Because you would participate in the bidding in the morning and a prearranged deal can be done provided your generator matches the highest bid? I guess I'm not understanding the need for the exemption, then.

MR. DALY: I think -- our proposal is to release

it to power generation. I think you said "provided the highest bid". And in that case, you wouldn't need it if you could assure that the generator always had the highest bid because that's not the occasion to marketplace. Other participants may bid on that capacity, unless it's a targeted release to generation, and that capacity could go elsewhere. And in the example that Tim Brennan gave, that capacity could be used for gas transportation for ENGIE exports for example.

MS. FERNANDEZ: My understanding of the current regulations is that, provided your generator matched the highest bided, your generator could always take that capacity. You would have like sort of a final right -- not "right of first refusal" -- but you would have the right to bid on that capacity, and provided that you matched that highest bid, you would get it.

MR. DALY: Yes, that's right, with the proviso you just mentioned, yes.

MS. FERNANDEZ: So I guess what Richard was saying is one of the concerns was being able to release capacity at a time outside of sort of the current bidding hours. But what I hear you saying is that you don't want -- part of the reason for the request is you want to avoid having your generators match the highest bid. Is that correct?

MR. DALY: We aim to maximize the revenue from the bidding, I mean, it would be competitively bid by generators. We aim to maximize the revenues from the release. So if the generators are always the highest priced payers, they will always end one the capacity. How can we assure that happens? We can't tell them what to the bid and we can't make them bid the highest price. Maybe they have another capacity and they don't need it. So if they don't need it, then we release it to the rest of the market and have that be the source for the maximum revenue for everyone else. But it's a staged release, first we want a target generation, and then to the degree the generation pays the highest price it will go there anyway. And we believe the most efficient generators will be the highest price, if they afford it they're more efficient. After that, we want to release it to the marketplace. But in the first instance to be assured that it's going to be used for power generation particularly during the peak periods of time, we want the targeted release for it. And then after that we are proposing to release it to the market generally.

MR. GOLDENBERG: To follow up, I'm not sure I understand why there would be a situation in which a generator bids in your little market and they bid, let's say $50 an MCF of capacity, and a replacement shipper in

Algonquin's auction bids $55, and you're saying that generator, even though they're being dispatched by ISO New England, is not going to match the $55. I'm not sure -- why do you expect that that generator will not be able to retain the capacity by matching the highest bid in the FERC auction that's run by Algonquin rather than your auction between only generators? It seems like that would maximize your revenue from the release, because instead of getting $50, you would get $55.

MR. DALY: I think if we could assure they were always going to pay the $55 in the example, then we wouldn't need it. But I don't think we could be assured of that.

MR. GOLDENBERG: Why wouldn't they if ISO New England needs the generation and they're the generator that's being dispatched, why would they not match the $55? Otherwise they're not going to be able to run because they won't have natural gas.

MR. BRENNAN: I think some of them would think as even we have seen in the reliability in the past winter they would think that they could still get something from the spot market. And they're all trying to think if I'm going to be dispatched ahead of another resource or not. And even those ones who may want to bid to what they think is going to be the price, there's a certain limit, if

there's another resource there or another potential bidder, if it was up to them, whether it was an extreme example that someone says "I can just take this to Canada, liquefy it or export it", or maybe it's another shipper who says, "I got a better idea: We'll loop this back to New York", to that extent you can do that. They could be bidding and then we would not be solving the reliability of price volatility concerns.

Clearly, we're asking our customers to buy this to make sure it's available, sufficient supply is available to be used to generate electricity and address those concerns. And there is the potential that there would be others, for whatever reason, who could outbid a generator, a generator that's having trouble being convinced they're going to be able to recover that price in the market or not, or any particular owner where they think they're needed or not, they might not get dispatched until reliability assurance system that runs later in the day, they might be called at the last minute to fill in for a contingency.

So we want to do everything we can to make sure that capacity is available to the generators first in those circumstances before we release it to the general market, because there is the potential, whether you believe it will happen often or only extreme cases, but if it

happens only once-in-awhile extreme cases it could cost hundreds of millions of dollars and over, billions of dollars, in a winter, as we've seen.

So we feel it's such a reasonable request that if we're buying the capacity for, in a sense, argues for a particular purpose, give us the opportunity to use it for that use first as we do in the LDC example before we release it to the rest of the market.

MR. HOWE: Your program includes the capacity manager issuing request for proposals and then like the winning request for proposals is determined by the Committee of the EDC's. Would you have purely objective standards for choosing the winning requests for proposals? Could they determine by a third-party without any exercise or judgment or is there some reason or benefit to be obtained from having a kind of a discretionary look at the request for proposals and deciding which was to accept or not to accept?

MR. McCAULEY: The intent was to do the RFP such that -- to answer your first question: It would be objective, we would set the release such that it would be pretty plain as to what the term was for the capacity release itself. In doing the RFP and getting the results back, what we wanted to do was that we wanted people to be as aggressive as they possibly could on their releases, but

we understood that the whole market, they might not necessarily want the whole market to know what their particular bid is, that might telegraph a company's position. So the thought was that do the RFP, get the highest bid result back, and then post that bid out on the bulletin itself. It would preserve confidentiality between the marketplace and all of the generators, it might want to get into the capacity itself because if you just do a regular bid, there's an auction out there and people could bid it out. Some people might not want to show what their best bid is, but we want people to be able to show and know that's it's going to have confidentiality, "Here is the highest bid for the period, the term, the volume", that it will be released, and it will be seen by everyone and it preserves that confidentiality between all of the generators.

MR. HOWE: But is the winning bid going to be chosen just pursuant to purely objective standard or is there going to be some objective exercised by the special committee?

MR. McCAULEY: It would be purely objective. We might put a reserve price on it. We don't want to accept anything less than blank on the release. But it would be purely objective as far as who's paying the highest for that asset.

MR HOWE: In your precedent agreements, is the entire capacity that you're going to obtain going to be no notice or is part going to be no notice in some standard firm transportation?

MR. KRUSE: The service that Algonquin is offering is no notice service for the 900 a day pursuant to the terms of the reached agreement.

MR. HOWE: Now, that no notice service seems to include, or at least the LNG storage component includes the two injection periods as I understand it. How is the release to the generators going to work if there's a separate injection period and withdrawal period? I guess for the releases that are one year, the generator will get -- will be responsible for doing the injection of LNG, or is it the responsibility going to stay with capacity managers?

MR. McCAULEY: It could be both where we would release a portion of the field available to the market where they could choose to have the transportation capacity and some of the capacity of the field and injection withdrawal rights and it would be their decision to go ahead -- if they want to take it for a whole year, they need to be able to control the injection and the withdrawal piece. And then there could be a percent that would be retained by the EDC's to sell a bundled sale service of the

number of services.

MR HOWE: And then the EDC retains it, how is the pricing of the sale of the LNG going to be in?

MR. McCAULEY: The price itself?

MR. HOWE: Yeah, for the LNG, for the gas of the price commodity.

MR. DALY: If I could have a shot at that? The gas commodity, we source the transportation piece and sold it to the marketplace to again maximize revenues. So we would sell it at the highest price, which would likely be the city gate index program, would be the commodity on those variable charges. So that if you like the impact of it to the marketplace is that it's increased supply, therefore, it will likely reduce prices because it's increasing the supply into the market. The laws of supply and demand will cause the price to decrease and will maximize the revenue from it. So what we're doing is maximizing the revenue from the sales, increasing supply into the marketplace, maximizing the sales revenues which will then go ahead to offset the public offices. So we think that's the best pricing algorithm for the marketplace that fits with how the marketplace works today in terms of people relying and buying their gas and it's the least disruptive, if you like, and fits to where gas gets priced, but at the same time maximizing the revenues back to

customers.

MR. GOLDENBERG: I have a question for Richard Kruse. Is the LNG necessary to support the no notice service?

MR. KRUSE: Very much so. I mean, it's an integrated component of basic ERS service. And there's really two aspects as envisioned currently to the ERS service that is no notice: One is the capability to nominate transportation at any time during the day. So we're able and we're committing that the capacity will be there committed to new gas firm from the receipt points to any of the prior generation plants on a firm basis whenever nominated during the day.

The LNG storage tank provides the capability to support non-ratable take flexible by the power plants. We are a pipeline that is largely designed on a non-ratable flow basis. We do have a six percent hourly swing that LDC's hold for some of the services. But most of the capacity is designed on non-ratable flow.

So having the LNG tank on the east end of the system will be critical for us in terms of being able to meet the non-ratable tank requirements for the shippers, as well as the feature that was mentioned where the generators coming on, say in the middle of the night, he does not know where he is getting his gas yet, he hasn't made

arrangements. And if he has the service on the release basis with the LNG there, we're able to let him flow gas for up to two hours knowing that he can go out and find gas and make up his imbalances during the day or at the end of the two hours we can take it out of the LNG tank as a no notice supply and maintain our confidence, so. So it's very much an integrated component of it.

MR. GOLDENBERG: So how does the release work when the asset manager who holds the gas in the LNG releases capacity, are they going to be releasing storage with it? And there's going to be a sale of gas so that the shipper now holds the gas in the LNG storage? I'm not sure how the mechanics of the release will work.

MR. KRUSE: The service has been structured to be releasable in segments so that to the extent the EDC's want to release purely transportation from a given receipt point to a delivery point, they'll get that component. If they don't get the full package of the service in a release basis, they won't have all of the features of it. So they can just get transportation, no notice transportation. If they want the no notice that the LNG provides, the non-ratable guaranteed flexibility, they will need to work out a release that is a pro rata share of the entire service rather than just a segment service. But that is something that the market and I think that the EDC's will

structure in their release efforts to one maximize reliability and to maximize revenue collection for the benefit of their customers.

MR. GOLDENBERG: Would the generators that want to take advantage of the no notice service have to acquire the gas that's in the LNG storage as well or a proportion of the gas sufficient to cover that service?

MR. KRUSE: Well, I mean, a given generator I guess could benefit from either buying that gas in the secondary market, and we having it withdrawn, or if they want that service and they want that control they're going to need to require the rights in the storage tank as was alluded to. But --

MR. GOLDENBERG: I had a question for the EDC's. Before the Commission granted sort of the blanket exemption for state retail access programs when they were just starting up in Georgia Public Service, the Commission actually required that the program be filed with the Commission so that we could review how the capacity would be allocated within the program. So if we granted Algonquin's tariff and accept it, will you be willing to file your programs so we can see exactly how you envision dealing with all of these secondary market implications that a lot of people have raised?

MR. McCAULEY: Yes, I think we'd be willing to

do that, I think it would be a good idea for transparency.

MR. SPARBER: This is for Eversource. In describing the role of the capacity manager program, Eversource has stated that capacity manager will issue a request for proposal to generators. And they also say that the capacity manager will ensure the release is executed in accordance with the energy Commission rules, including pipeline posting notice requirements. What exactly does that mean in terms of the issuance of the RFP and who receives the RFP criteria for participating in the bidding process, and basically the universe of potential bidders?

MR. DALY: If I could defer to my colleague here who's more experienced on the scheduling side of the business.

MR. McCAULEY: So as I said before, the RFP would be issued to all of the generators in the region, and then when we posted the prearranged shipper, FERC rules as far as making sure that the flag is noted, that this is an exempt release, and any other requirements from the bulletin board as far as what is similar to what we do with the escrow or managers themselves. So the part we're asking for is really just the exemption similar to asset managers and to escrows themselves, and then everything else would adhere to traditional FERC capacity releases.

MR. SPARBER: In terms of the criteria for

participating in the bidding, I know you mentioned credit before. Would the credit worthiness, or general credit worthiness, rules apply in terms of the process is qualified to bid?

MR. McCAULEY: From a credit perspective, I think we would treat it just like capacity releases just like LDC's do. The pipelines themselves go to FERC requirements for order of shippers, and that would be done -- I believe my thought was that that would be done by the pipelines itself. There might be credit requirements from -- if we do a bundled sale that real wouldn't pertain to the capacity itself. But if it would be assets that would be retained by the capacity manager and then made available to the market through bundled sales.

MS. FERNANDEZ: Tom and Joe, who have been waiting a very long time. You guys go ahead and ask your questions. And then after you're done, we'll then come back. So you guys go ahead and go first.

MR. LOCKETT: Tom Lockett from Tenaska. I have three-pronged clarification request, all under the topic of secondary markets. I think the first and third clarification will probably be directed to the EDC's, and the middle one probably to Spectra, but I will let you figure that out.

First of all, I think I heard that the EDC's or

their affiliated capacity manager would be the exclusive party selling bundled sales, so I'd like to get a clarification on that. I think it heard it was alluded to that on an off-peak period that there could be PRS capacity that may be available to the secondary market. I'd like to just understand: Does that include non-generator, non-EDC secondary markets, as your PRS tariff has proposed specifies the definition of a shipper, so therefore it's a primary shipper or a replacement shipper, would be an EDC power generator? I just want to know how another party might step into that.

And then the third prong is, the LDC's currently enjoy the benefit of asset management arrangements under Order 712. They receive money, they receive a service, they have first call on capacity. I don't think that there's been any issues of reliability. If there are, that capacity could easily be recalled or the assets management arrangement could be terminated.

I'd like some sense of how using that methodology, especially in light of the fact that Spectra has some 30-odd nomination schedules during a given gas day, how using that same AMA methodology under Order 712, how the service would be degraded for power generation?

MR. McCAULEY: As far as the first part, I believe is your question about EDC's whether it be

exclusive bundled sales done by the EDC's. I would say no to that. The EDC's may all choose to have one capacity manager, they might elect their own capacity manager, they might elect to manage the capacity themselves. So depending on how each EDC decides to do in the region, there can and probably most likely will be multiple sellers of bundled sales capacity out there.

As you said in the off-peak period if generators do take capacity for a while year and now available to them and it's an off peak period, they'll be able to use the capacity to make bundled sales in those kind of cases. So I think that there will be multiple participants out there that will have the ability to make bundled sales. And you'll have to go back to the third part about the asset manager. Could you repeat what that question was? Because I didn't follow.

MR. LOCKETT: Only if using typical pretty standard protocol right now, the LDC's issue RFP's for asset management arrangements as defined in Order 712. The capacity that they bought and that they're allocated to this primary party was for their primary use, they have a call option. They can call on it pursuant to whatever the AMA agreement looks like. They call up hourly, daily, monthly, it seems like, what have you. And I am just wondering, given the fact that Algonquin has some 40-odd

nomination opportunities in a given gas day, why a similar mirror image process would not be available to power generators and how might it be degrading power generation? It seems like the system works right now for LDC's reliability, recall option, the benefit to ratepayers are all in place. Why wouldn't you take a similar path with power generation and just let the market continue to work efficiently and reliably?

MR. McCAULEY: I'm going to repeat the question to make sure that I did understand it. So I think what you're asking is release capacity to a generator who then -- who can then select their own asset manager to manage their capacity for themselves. And you're saying why not have the same mechanisms today that the LDC's, is what you're suggesting that the LDC's then have the ability to recall the capacity if the asset manager for the generators is not using it for the intent of generating electricity.

MR. LOCKETT: I'm not so sure it's the intent. I'm going through mechanics -- I'm sorry I'm getting into the weeds here -- but if an EDC releases it to a power generator, a power generator rereleases it to an asset manager who's going to economically get as much value out of that capacity as possible. For some reason the power generator is not able to obtain gas supply is dispatching that particular unit, then I would see no reason why the

EDC couldn't recall that capacity, even though it's several steps in that line, which is exactly the way it would happen right now with an LDC. And I'm just confused as to why you wouldn't follow a similar proven methodology in terms of economic efficiency and reliability.

MR. DALY: I think we could, we could operate like that under the program. A lot of the terms of the capacity managers' operation in this has not been finalized, if you like, with the states, I mean, we are getting precedent agreements approved at the state level at this point. When we get to and we have committed to work with the states in terms of the form of that capacity manager agreement, once we know what the rules of engagement are that could be well within the scope of how we operate it. We just haven't got to the weeds, if you like, of that transaction at this point.

MR. LOCKETT: So if you did get to that sort of end result, I think it comes back to also just the definition of the shipper within the ERS tariff would have to be changed, just some clarification on that. To be something just beyond the exclusive EDC power generator, there's other parties in the market.

MR. KRUSE: Well, in terms of ERS rate schedule, it is an open access rate schedule today, there is no limitation on who can be a shipper under ERS, it's open to

anybody. The project that we're designing is of 900 a day has been through various open seasons and solicitations designed for EDC's to be released to it, but there's nothing in the tariff itself that prevents an LDC and wants ERS service from contracting under. It's just that nobody has requested that service.

One concern that I would have, and the answer unfortunately when you talk to dispatchers is always "it depends", it depends on the day, it depends on what's happened, but one of the challenges that we have is we manage very much transient flows, non-ratable takes, to power generators, to LDC's, but when we're talking about power generators who will try to take as much as their daily as fast at they can because that's their electric requirements.

To the extent that that flexibility is being utilized in the secondary market, it's not being used to create electricity yet, it's being used to supply some other need. Halfway through the day when the EDC's see electric reliability need, recalling it at that point in time may be recalling something that has already been delivered from the system and we will be able to say, "I'm sorry. The market that had it before has taken that flexibility out of the Algonquin system and we have therefore lost that no notice capability." It's just the

way the dynamics work.

So the fact that we have 42 nomination cycles doesn't mean that halfway through the day you can call on necessarily the entire service that RES provided if, in fact, it was being used on a secondary basis for nonelectric reliability purposes. So that is some of the challenges I think that the EDC is going to have and the program is: How do they reserve its capacity for reliability? Because on a stressed-out reliability day if you're a dispatcher, it's not about the price, it's not about the money that's changing hands, it's about whether gas is able to be delivered when you need at the rates you need it. And that very well may beat saying, "I can't take the high price today, I got to reserve it." That is somewhat -- I bear with the EDC's, they have a tremendous challenge of putting their reliability first. And I think cost recovery is out there, but they're really out there to preserve reliability.

MR. DALTON: Thank you, Joe Dalton, ENGIE gas and LNG. I just want to offer an alternative answer to Commissioner LaFleur's question asked many minutes ago now, and I'm paraphrasing: Absent approval of this program, do customers see more reliability in low cost? The answer is yes. And in fact that happened. If we go back to the chart that showed the wholesale cost of the winter of

'13-'14 at 6.8 billion, people forget that the market operated differently, people behaved differently, you had -- you achieved a different result the following winter that was nearly equally has cold. I think in one month it was colder and over 100 inches of snow fell in New England. So yes. In this past winter we've had record send out on Valentine's Day, absent record cold and record sent out. So I think the answer to that question is, yes, there are alternatives to this notion.

Your second question was, who should bear the risk? Well, we have the reconcile the fact that in a number of these states' jurisdictions, electric ratepayers have been expressly removed from taking on a risk of this nature, which is why these issues are being contested actively in notably Massachusetts and New Hampshire where the state Restructuring Acts are very much in play with respect to states that reconcile whether or not approval can even be given to these programs.

MS. FERNANDEZ: John?

MR. RUDIAK: I had two questions. The first was for Tim Brennan and the second was for Mr. Daly.

Tim, when you guys were talking about winter price volatility and the electric markets, do the retail customers, the customers of the EDC's, see that price volatility in their bill?

MR. BRENNAN: Yeah, they do. Now, due to the procurement methods in some of the co-laddering where we might buy half the bulk service customer load, we might buy for 12 months and then six months later do the other half, so there's certain laddering at which caused sometimes the delay of the wholesale market volatility and winter prices hitting the retail bill. But what we did see, for example, a few winters ago when the wholesale market, the winter before had risen by about 90 percent, the supply side being about half of the retail bill, it was the next winter where we saw a 40 percent increase in the retail bill due to that winter price volatility. And, again, there was some mention about the following winter being better with double the LNG, but we still paid by our calculations by 1.6 billion what by would have paid with the unconstrained system and adequate infrastructure. And so even that following winter, reacting to the not-quite-so volatile and extreme prices due to different weather and additional LNG imports, we saw only a 20 percent. I say "only", but we still saw a 20 percent increase due directly to the infrastructure inadequacies in the retail bill.

MR. RUDIAK: My question was more retail electric customers pay an average price. Right? They don't pay a daily price for electricity.

MR. BRENNAN: But the volatility and the average

extreme prices we've seen over the winters all factor into those bids that we often see in the retail bill. So certain days, when it went to $30 versus a $3 availability just a few hundred miles away, that winter might have averaged $13 on average higher all winter. So both the 30 and the average 13 all get figured in and the risk and the expected price of those taking over our load-serving obligations, both for our customers and the competitive suppliers who are serving a lot of our industrial customers. So it does, there is a lag, but all of that, those average price increase we're seeing in the winter due to infrastructure and the extreme volatility, it all gets eventually shown and reflected in higher retail rates.

MR. RUDIAK: Next question is for Mr. Daly. James, you said the RFP that resulted in your current contract that you're seeking approval at that state level that went out on October 23rd 2015.

MR. DALY: That's right.

MR. RUDIAK: If I'm correct that the Access Northeast project started as a joint venture between Northeast Utilities and Spectra, each owned 50 percent back in 2014?

MR. DALY: Well, in terms of when it started, yes. I can't tell you what percentages were talked about because I don't work that side of the business, that's the

development side of the witness. I'm on the electric distribution side, the LDC side. So in terms of putting the project together, there were discussions that eventually which led to 40 percent of ownership and National Grid has a 20 percent ownership.

MR. RUDIAK: National Grid came in with their 20 percent in February 2015. Is that right?

MR. DALY: It came in later. I can't put a date on it.

MR. RUDIAK: All right. Thank you.

MS. FERNANDEZ: I think we have one more staff question.

MS. JAYARAMAN: I think in the case of the chart that Algonquin, I think it's more of a question for you all, but I'm just referring to this chart for the purpose of: This kind of talks about northeast aggregation areas. So in these aggregation areas there are multiple states or generators from multiple states are covered. So one state gets appointed, and then you kind of release the capacity, how would you kind of create generators in that area that are not within that particular state that are approved program? And number 2, also in terms of electric reliability as you mentioned when you were kind of inquiring the cost, it also has a locational impact but you do mention that you will release it equally for everyone.

So for the actions, there might not be, I just want to get some comments on it.

MR. DALY: Sure. In terms of the program itself or the Access Northeast facility, we're entering into present agreements and filing them at the states for approval. So it's anticipated that, well, firstly, as an objective we want as broad as participation from the states that we can. So we have allocated a portion of that project to each investor-owned utility in each state. Now, there's nothing that we can't bind those entities to that, we can't bind the state or the industry-owned utility. So there's a process that each state is following to determine whether it wants to participation the project or not. So hopefully we will get enough participation -- and this is not unique to this project, it's similar to gas LDC's coming together to contract as well, it's a similar process. So at the end of the day we'll have a number of customers sign up for the service, and we have to make a determination, the project has to make a determination -- to get built. And if -- there's a provision in those presented agreements that there may be a reallocation of capacity among the participants at the end of the day or the project may get resized or it may get canceled altogether if there isn't enough participation.

We need to go through that process to figure

out how much of it is going to get contracted through the states. It is a laborious project. It is complicated, because we have all these different state proceedings and no state can tell the other one -- we're relying on what I introduced in my first slide is that the New England governors at that level want to participate in the infrastructure project.

In terms of which state participates or not, that's to be determined. But we don't envision that the service would be allocated by state participation. So it would be allocated to the market generally, and that would benefit whatever -- whichever power generation chooses to contract for that capacity. It could be in any state. So you could have, for example, a state that decides not to support this effort but have power generator that would be participating in this. We want to make it non-discriminatory that whatever generators are on whatever pipelines, they can all participate in terms of seeking this service. So we're not linking it back to which state participates.

MS. JAYARAMAN: Thank you.

MS. FERNANDEZ: And with that, we're going to break for lunch. Given the time that we've run over, we're going to cut lunch a little short just to make sure we stay on track and that every speaker gets to make their

presentation. So if I could ask everyone to be back here at 1:20. So I'm cutting lunch by 45 minutes, 1:20 reconvene.

Thank you.

(Recess.)

MS. FERNANDEZ: In the interest of time, we're going to change things a little bit in terms of how we're going to run the second half of the day and we are going to just do presentation, presentation, presentation, save the questions until the last speaker has spoken. So I ask if any speakers just be prepared to follow one another, and anyone who has questions to save your questions until the last speaker.

So the first speaker in the second half of the day is going to be John Rudiak.

MR. RUDIAK: Good afternoon. My name is John Rudiak, I'm here on behalf of the New England LDC Group. And I do have a presentation. Okay, thank you.

So our group is referred to as the New England LDC's. We're been working together for decades before the Federal Energy Regulatory Commission. So we're gas utilities and we're here in the interest of reliability and to offer a few comments with respect of our viewpoints. So we're here from the perspective of serving residents and commercial customers in a very constrained area. We

appreciate the opportunity to provide some comments today.

So with respect to the concept of Algonquin's proposal itself, we're very supportive of the concept underlying the proposed exemption from the capacity release posting and bidding requirements primarily because of the fact of the concept is supportive of reliability of adding infrastructure into the region. We feel that over the last 11 years or so when we have been working on some of the gas-electric coordination issues that the underlying issue is really the infrastructure issue. And we've been trying to get that raised and get it closer to a solution, and I think Algonquin's proposal and the EDC model is a step in the right direction to getting that done eventually.

In terms of the particular area that we're operating in and kind of stepping back a little bit here, the New England area is certainly perhaps the most capacity constrained area in the United States. Previous speakers talked about the prices of the constraints. We operate as LDC's in terms of all of these constraints every day in terms of restrictions, in terms of various factors of limitations, in terms of operational flow, orders, et cetera. And essentially when we stepped back based upon our contracts that have been developed since the '50's in terms of the infrastructure. And the system has evolved over time, but still was not necessarily designed in any

way to serve the electric generation demand.

So from our perspective, the current state of gas-fire generations without capacity poses reliability risks, posing reliability risks to electric customers and to a certain extent the gas customers, because we're all operating under a shared system. We have situations where we have pressures, pressure concerns, rapid pressure changes, et cetera, that we're concerned about. And we're serving our residential and commercial customers who have no dual fuel and essential service.

In terms of ongoing efforts, our group in conjunction with the rest of the gas industry has been focused on trying to work on these issues and problems for quite a number of years. I was thinking about coming in today that in September 2012 in Boston, we had a discussion, not dissimilar to all to this in terms or what is the underlying issue, et cetera. And from that point there was various task forces and focus groups that evolved and various studies were put forth, and all of them concluded that there's an underlying infrastructure need for electric generation in the region. And so that's just the backdrop of where we're coming from in terms of our perspective.

I want to mention a couple of things about the New England region in particular. The LDC's themselves are

dependent upon on the design peak day for about one third of our supply come from peak increases. So there's a very significant limitation that's on pipeline capacity in the region.

Another phenomenon that we've been increasingly concerned about is the emergent repairs, the unplanned maintenance, work sources that we've been experiencing over the last three or four years, much more prevalent than historical on the pipeline systems. Often there's maintenances that are required that are sometimes in the middle of the winter. We're in a situation where we've just recently had a force majeure event that reduced our supplies significantly intraday due to the Del Monte unfortunate incident a couple of Fridays ago. And from my companies, for example, we experiences a 90 percent reduction on our deliverance of supply that day. And we're not saying that that was in any way related to gas electric, but it's an example of some of the warning signals that we've been seeing with respect to the pipeline infrastructure and the stresses on the pipeline infrastructure and the limitations in terms of slack on the system.

In terms of our own perspective, too, some of our companies have been around since the 1800's, we have a very long-term focus. We've not necessarily interested in

short-term trading opportunities like that; our focus is serving the customer in a reliable manner, today, yesterday, next year, ten years from now, 25 years from now, that's our focus.

So when we step back to the situation that we're in right now -- and there was a question by Mr. Howe earlier in terms of the development of electric generation holding capacity -- well, in the 1990's I recall there was a significant buildup of capacity built for electric generations in the New England region that led to a lot of debate about incremental rates and deposal rates, et cetera, but there was a significant buildup in terms of pipeline infrastructure at that point. Over time that has all dwindled and, for example, my company and other of my LDC colleagues have been contracting in lieu and stepped into some of those contracts over the last 16 years.

So this is an issue that has been going on in terms of the infrastructure issue since 2004, as Mr. Kruse mentioned. From our perspective in terms of scheduling, tremendous progress has been made in terms of communication over the years. But the underlying issue of the infrastructure, and the funding logjam that we call it, has yet to be fully addressed. That's why we view the Algonquin proposal it be a step in the right direction.

A couple of points with respect to the EDC model

in particular. I think as we look back over the last four or five years and we think about the efforts to come up with solutions toward the underlying infrastructure issue, this EDC contract model has emerged. And we've been paying some attention to the state reliability program in the various states, obviously they're quite controversial. But again, a step in the right direction.

In terms of a couple of other points with respect to the particular section 14.16 that Algonquin has proposed, why we think it's beneficial toward the region and from a gas and electric perspective, is that it would assist the functioning of the EDC model. Certainly, there's been a lot of discussion this morning, certainly the proposal is not perfect at this point. But again it's a step in the right direction in terms of addressing the underlying concerns.

In summary, our overall goal is to preserve and enhance the reliability of service provided to our gas customers and offsetting a significant benefit of the proposal, though at Algonquin, is the reliability to electric customers also.

We think that the Algonquin section 14.16 concept will support the construction of needed gas prices and electric generators, and help to ensure that the new capacity is used for this purpose. So the LDC's in the

region have been the case that have signed up for the recent projects in the area where some of the significant supporters and subscribers to the Algonquin project in Connecticut and recently-suspended Tennessee NED project and the Atlantic Bridge project.

So our perspective is we think that when there is a situation where firm needs are necessary, the infrastructure is necessary and needs to be built to serve that particular entity. We think that from a collective perspective that the Algonquin filing and proposal is definitely a step in the right direction.

Thank you.

MS. FERNANDEZ: Thank you, John.

MR. COYLE: Thank you. I don't have any visuals. When I started working on this, it turned out that my colleague in the AG's office Christina Blue wasn't going to be able to make it. I kept coming from to a speech that Warren Buffett's business partner Charlie Monger gave Harvard Law School about 20 years ago called the "Psychology of Human Misjudgment". And if you haven't read it, I command it to your attention. Among those two, a number of decision-making biases that humans have that tend to lead to bad decisions. And I think as we walk through, at least the AG's position on Algonquin's exemption proposal, you'll see some of them at work.

Our basic take on this can be summarized in three points: Number 1, the exemption proposal is premature. The state programs in which it is supposed to be an aid do not yet exist. They may never exist. They're hotly contested, and I'll get to some data points on that in the moment.

Number 2, in its present form the proposal is discriminatory in the sense of an older line of Commission cases I heard somebody earlier in the discussion on the staff panel cite back to Georgia Public Service Commission. And I think that this proposal exhibits the devices that were noted in the original Georgia Public Service Commission 107 FERC and left as unacceptable under various rehearings.

The third thing, and I think this is sort of an overarching point is, it's a mistake to try to second-guess markets. Markets, as everybody knows in this group, are complex things, they are the balancing of a lot of interdependent forces. You have a traditional facilities expansion model under the Natural Gas Act, most recently reformulated I think in the pipeline certificate policy statement. But expansions are market-driven. Merchant generators are not asking you for this capacity, and you need to ask yourself why.

Let me go back and now start with a couple of

data points which I hope will be helpful to the Commission. On the first point, prematurity, I would note that on May 5th, 2016, the Massachusetts Supreme Judicial Court heard oral argument in Case Nos. SJC-1205-1 and 1205-2 under the caption ENGIE Gas and LNG v. Department of Public Utilities, which is a challenge to the Department of Public Utilities' order of VPU order in 1537 that held that electric distribution companies had the authority to contract for gas pipeline capacity under Massachusetts law.

So that premise is at the moment contested in state courts. The supreme judicial decision will issue its decision on review in due course, but there's no current deadline. I think a decision's expected probably after the end of the September 1 suspension date in this case. The currently ongoing VPU proceedings in Docket No. 15-181, which are Eversource's application for approval of it's what they call the precedent agreement or proceeding agreements, would be acquisition of capacity on the Access Northeast project, is currently on a suspended procedural schedule with the hearing officer calling for amendments to the procedural schedule, again will probably produce a result maybe sometime in October in terms of a hearing officer's report, and we really don't know when the VPU is going to act on that. That delay also affects VPU No. 16-05, which is the National Grid operating company's

application for the same kind of approval. The Massachusetts Electric and the Nantucket Electric in the 15181 docket is Eversource and its operating companies, N Star and Western Mass Electric. So there's no driving sense of urgency.

The proposal, as has been noted, refers to state-supervised electric reliability programs, but you don't know whether or not those programs are going to exist. I neglected to mention the New Hampshire docket, New Hampshire PC docket DE 16-241, which was filed by Eversource Operating Company Public Service of New Hampshire, in that case on April 28th, the New Hampshire Office of Consumer Advocate filed a brief arguing that the capacity acquisition program is equally unlawful under New Hampshire law.

The next point that I wanted to offer also as a data point, is -- I don't think it's a secret in the room but I haven't heard it talked about in the course of the proposal -- is that the project, in aid of which this exemption is sought, is owned 60 percent by the utility holding companies that are in effect of electric distribution companies. The Eversource SEC110K report for 2014 states at page 12: "On September 6th, 2014, NU and Spectra announces that Northeast; on February 18th NU Spectra Energy and National Grid, as a codeveloper of the

project for total ownership of 20 percent with Northeast Utilities and Eversource, and Spectra Energy each owning 40 percent."

So there's a certain amount of opportunity here for this venture, to put it as neutrally as I can. The proposal is discriminatory in the sense that is creates a class of customers, EDC's, which have a set of rights with respect to the capacity that nobody else has.

Spectra has argued, Algonquin has argued, this is fair because the retail electric customers are being called unsupported. The problem is, as that line of Commission precedent rooted in Georgia Public Service and carried forward I think most recently in Order 809 -- I can't remember the footnote, sorry -- anyway, retains vitality in the anti-discrimination requirement, that you can't have a preferential exemption from capacity bidding requirements. And this is in its current formulation a preferential exemption. Can you fix it? I don't know, maybe.

One of the ideas we toyed with is the possibility of requiring -- and I heard this discussed by staff -- someone requiring this capacity out of release paid maximum price for it. And the problem is you then get into the sort of convoluted relationship between the financial obligations of the electric distribution

companies' retail customers and the need to maximize cost recovery there, and whether that capacity would be optimally absorbed. It's a very complex business arrangement because it takes decisions that Commission policy generally commits to the marketplace out of the marketplace.

Now, my third point is it does so in the context of a claimed crisis of constraint on Metrogas transportation system in New England, as to which there is considerable debate whether or to what extent that system is actually constrained. While Eversource has pointed to an ICF study as part of their VPU filing, Mr. Daly averted to in his remarks today, there are studies including one by the analysis group done for the Attorney General's Office which point to the opposite conclusion that the system is not, in fact, currently constrained and won't be for some time. There's another analysis by Skipping Stone, an energy consultant and law foundation which comes to a similar conclusion. I'd be happy to post those, file them, tender them, if they're of any interest to the staff. But I don't think it's wise to accept at face judgment the notion, a topdown notion, that there is a problem with infrastructure that the market is not telling you is a problem.

Collateral to that point, I think you have

received some input in this proceeding that indicates that merchant generators in New England have adapted to the demands of the natural gas transportation system. I noted, for example, in the Calpine NRG and PSNG joint intervention in this case, the authors of that intervention noted that there are a number of pretty creative brokerage arrangements for delivered gas that the merchant generators use to circumvent the pipeline constraints. One of the -- again, going back to the Skipping Stone study -- there is underutilization of liquefied natural gas capacity currently to the system.

And finally, I think, although I was told not to stray too far into the electric market, I wanted to offer you one interesting data point about the effect of something that the Commission had authorized back in 2014, sorry, ISO New England pay for performance regime which penalizes merchant generators with a capacity obligation for not producing when called upon.

The penalty structure is fairly onerous. The penalty starts as $2,000 a megawatt hour for energy not produced in 2018, June 1, 2018, power year, that ramps up to $5,455 a megawatt hour in 2024, and thereafter. That is a serious incentive to make sure that if you go and take supply obligation you have firm fuel.

One thing that the marketplace has done about

responding to that, aside from creative arrangements for gas transportation, is that if you take a look at the last two forward capacity auctions in New England, the successful bidders for capacity supply obligations, fossil fuel capacity, have with one exception installed dual fuel units. That translates to -- and I can provide the units and the names if you want -- but in FCA9 a total of 965 megawatts of new fossil fuel capacity of which approximately 875 were dual fuel.

In capacity auction 10 just concluded back in February there was a total of approximately 1,300 megawatts of new fossil fuel-generating capacity, all of which was dual fuel. Over the two most recent forward capacity auctions, they've added a total of 2,268 megawatts, of which 96 percent is dual fuel.

Why is that useful? I mean, it is useful to you because you're being told by Algonquin that the price signal that is supposed to incent or signal the need for new pipeline capacity has been broken. And I think that argument is fundamentally untenable in the context of the Natural Gas Act. I'm referring to Algonquin's answer to protest on page 12, and I'll quote it: "Price signals for new pipeline capacity are currently broken due to the separate ownership of generation transmission and distribution."

When customers are not willing to commit to long-term firm pipeline capacity, despite the existence of persistent peak period shortages, the appropriate signal for Algonquin to expand is not protected."

I could say a lot of things about my friends in the merchant generation business, but I'll say two in this context: (1) They're not stupid; and (2) They don't like to lose money.

I would suggest to you that what you're really seeing here is, on the generation side, a financially self-interested, market driven response to whatever stimulus the merchant generators are encountering. But they are responding, and they that's responding just fine. It isn't a question of price signals being broken; it's a question of price signals operating in a way that is not understood in the context of a traditional topdown utility planning and operation.

We're not dealing in a system of integrated resource planning anymore, and that's the link that's been broken. But it has not broken the market and it has not broken the price signals, the price signals are just operating, it hasn't been understood perfectly.

The idea that Algonquin's exemption proposal somehow replaces the price signal that needs to come from its market with a price signal that comes from EDC's I

think is a dubious proposition because I don't think that the retail customers who are supposed to be the ultimate beneficiaries of this have actually been heard. And that's my job.

So I thank you for your attention.

MS. FERNANDEZ: Thank you, John.

Next, we have Craig Adams.

MR. ADAMS: First of all, I want to thank you for the statement that merchant generation isn't stupid.

(Laughter)

As a fuel guy at a power company, it's rare to be told I'm not stupid, so I really appreciate that.

Again, I'm Craig Adams. I'm director of gas supply for Calpine Corporation. I appreciate the opportunity to join you here today and give you some perspective as to how merchants operate and gas procurement in a deregulated world.

I just want to try to share our perspective so that staff or any other interested parties might understand the role of capacity release products hopefully play in our market. So what I'm going to do here is, you know, rather than speak to the merits of the Access Northeast project, I want to speak specifically about -- I want to talk about what Calpine does and why we think we have a unique perspective to bring on gas procurement policies and things

of that nature, and then speak specifically to the waiver rather than to the merits of the overarching conversations we've had.

So Calpine, we are -- we own and operate a national fleet of gas-fire generation, we got significant serial in all U.S. competitor power markets. As you can see here, we have roughly 27 gigawatts in generation at eight world locations. We got 17 gigawatts of combined cycle generation. We're the largest in that market in the U.S. We got 6,700 megawatts of combined heat and power, or commonly known as co-generation, in the lower 48. We're also the largest participant in that market segment. 2,900 megawatts in simple type of peakers.

In California, we've got just under 730 megawatts of renewable generation, that is geothermal in Northern California. We're the largest geothermal producer in the country. The average age of our fleet is about 11 years, average heat rate for the fleet is about 7,400 BTU per kilowatt.

We generated last year just under 115 megawatt hours in 2015 under, I think, conditions anyone would be challenged to disagree were challenging. We operate in three geographic segments of roughly equal size.

We've got 7,400 megawatts out West, including 725 megawatts in geothermal. We've got 900 more megawatts

in Ercott. And then the East, which is everything east of the Rockies including our Canadian assets, is 10,400 megawatts of generation. We're the largest gas-powered generator in the country. We're the largest industrial consumer of natural gas. We consume an average of 2.4 BCF per day, day in and day out. In 2015, we burned 878 million cubic feet of gas.

Our total cost on gas supply was about $4.5 billion, approximately 200 million of which was direct transportation storage cost, almost every case that falls directly to our bottom line.

Natural gas is the primary fuel for our entire fleet, we use renewables out West, and we have significant backup capability in the East using ultra-load sulphur diesel. Now, I want to qualify that statement by reinforcing that it is ultra-load sulfur diesel that is the same fuel that is used to fuel over-the-road trucking. The oil when you traditionally refer to an oil-fired generation, you're talking about residual fuel. And we have no residual fuel on our fleet, at least none -- be have a small unit in Delaware that never runs. But the realities of dual fuel facilities now using ultra-load sulphur diesel as compared to the bad old days of RFC are significantly different.

So, continuing on, again -- I got ahead of

myself here -- we manage all of our commercial operations from our Houston trading port. Just to give you a point of reference: If the gas desk were an independent marketing entity, we'd be a top-15 marketer by size. Effectively, we're a top-15 aggregator with one customer, our power front desk. We're currently active on about 40 pipelines with interstate and intrastate and monitor virtually every interstate and pipeline in the country on a regulatory perspective.

How do we fuel our fleet? Well, since we're a gas-only generator, we have to have a particular degree of expertise in gas procurement, logistics, and optimization. I use that order very specifically because optimization is not the first thing on our mind. Fueling the fleet in the most efficient manner is why my group exists.

There's a wide variety of commercial products and structures that we use to fuel the fleet and to manage our risk. We will buy gas on any number of different vendors. We've got some mid-term about three to five years. Day-ahead and generally the most common products, and then we also buy intraday.

Now, I want to qualify that by pointing out that in most cases, and in every case in New England, we're in a fairly significant amount of risk when we go out and buy gas for turn, because in almost every case power clears

on a day-ahead basis, if not real-time. So we're talking some risks by locking gas up for, for instance, the month of June, unless there is an over-the-counter market that allows us to manage that power risk.

It's rarely the case that there's enough liquidity in the marketplace for us to buy all of our gas needs forward and match that power risk, but that's one of the educated risks that a merchant generator has to take.

We also use backup fuel fairly regularly, and I mentioned sulphur diesel. I'm going to nod my head down at the end of the table to Repsol and ENGIE, they both play vital roles in how we manage our fuel obligations in New England. We do have some transportation and storage services that are managed internally, but the largest source of our supply in New England is firm-delivered supply.

So what is firm-delivered supply? For the most part in New England, we're buying a delivered product. While Mr. Kruse said that only 8 percent of the firm transportation on Algonquin serves the generators, I think that would be a point that would have relevance if it were true that there were not other transportation holders in the marketplace such as Repsol, such as third-party markers, and also if the LDC burn gas every day; neither one of those is the case.

The most common -- we really have two mixes of suppliers in New England: Third parties that have capacity but aren't necessarily are LDC's, again, I'll point to Repsol and ENGIE. Now, we have some fairly significant inhouse experience with asset management. Calpine does not get involved with asset management directly. We have had some conversations with asset managers such as Tenaska, Sequence, VP, about how we could partner up with them. We feel like we would provide a unique value opportunity in that regard because, as I mentioned, we burn a lot of gas.

So to the degree that an asset manager is bidding to manage a suite of assets on behalf of utility, we can provide the asset manager with a certain value that they can monetize the off peak piece of that fairly effectively. Now, I say off-peak because that capacity is only available if it's not needed by the incumbent utility. We understand that. The asset manager understands that. The generator can only use capacity that goes unused by the LDC. If we can't be served by such capacity, we make the decision to go out and buy spot-delivered gas or burn oil, and bid the unit into the ISO accordingly. Again, I appreciate Mr. Coyle alluding to the fact that we do actually try to think ahead and try to think about these things a little strategically.

The term "interruptible services," I cannot

remember the last time we scheduled IT other than for something that was to correct either a cleanup mechanism post-cycle or about something that was not a significant part of our portfolio, it hasn't been for quite some time. Our procurement strategy changed in real-time. We will ramp a plant up and down based on orders from ISO New England. We will reset our offers to the degree that we can as gas supply, prices change in intraday markets, we keep ISO New England informed of those decisions in real-time. Every plant is different every day. So we try to stay ahead of that by monitoring forward price dynamics. We got our own inhouse meteorology staff that actually does a pretty good job of keeping us on top of the weather changes and allows us to be proactive in supply planning.

So with that being said, let's proceed to our New England assets. I know that the organization NESCO has been mentioned more than once here. We have worked very closely with NESCO; I've given them presentations both at the NESCO level and at the independent state level several times. So we are happy to work with them.

As far as our New England fleet, we have three of the newest combined cycles of facilities in the world. There are 1,500 megawatts of maximum gas loads with about 400,000 decaterms per day. The minimum can and has been zero, not due to constraint, due to market conditions. So

what that means is that power prices have been so low that it has not been economic for us to run any generation for fuel. That's another dynamic of being a merchant generator.

The first facility we have in the upper left-hand corner is our Upper Circuit. This is a 552 megawatt two-by-one combined cycle facility just west of the airport in Bangor, Maine. That facility went commercial in 2001. Calpine bought those and built the project and has owned it ever since. Fuel for this plant comes from the joint facilities of Maritimes and Portland Natural Gas Transmission. We have dedicated a lateral from Maine natural gas to max load of 90,000 a day. I have been responsible for this plant for the last four years, and prior to that had looked to see how the plant was fueled. The amount of the gas has been delivered to that plant for the most part, I would say 95 percent of it has been delivered on firm contracts held by third parties, Repsol in particular; and then we have a long-term relationship with a marketer out of Canada that brings the gas across the top out of PGTS. Cray Energy Center on the top-right corner, this is the newest piece of our fleet, we just acquired it in early 2016. 745 megawatts and two-by-one combined cycle facility just west of the airport in Manchester, New Hampshire. I promise we don't use airports

as a primary siting tool, that's just where these two happen to be.

(Laughter)

We get -- AES built this plant. We acquired it early this year from the projects owners, a group of private equity companies. This plant is fueled by Tennessee Gas via a dedicated lateral from Liberty Utilities with a maximum load of 130,000 a day. This plant does not have dual fuel, so we do hold firm transportation on Tennessee Service Plant.

Finally, we've got Foreriver Energy Center down on the bottom left-hand corner. This is a 731 megawatt two-by-one facility plant southeast of Boston. The plant went commercial in 2003. We acquired it in late 2014. This is fueled directly from Algonquin via -- we're one of the southernmost meters on hub line, have a max load of 120,000 a day. We have -- I wish we had this much diesel storage everywhere, because we've got 4.5 million gallons onsite and then have access to a waterborne terminal with spray guns across the ship channel. So we have access to all of the backup fuel we would ever need. Because we're in Algonquin, we're actually able to get a discount in the index.

We also have a retail provider that has recently become active in New England, Champion Energy

Service, retail, commercial, and industrial marketer active in Maine, Connecticut, and Massachusetts and again, we play a very significant part of our supply mix, both tactically and in the day-to-day market and long-term.

So with that being said, let me kind of draw this up into a conclusion. We appreciate that this proposal is tangential to the broader New England dialogues, and that is ongoing. First, is this individual pipeline capacity needed? I don't -- I can't answer that question, but I can point out that we've participated in all three open seasons offered by Algonquin at least informally, Algonquin incremental market and Access Northeast. We've not been able to reach terms with Spectra because they weren't selling a project that we could necessarily fit into our business model.

Is the goal to increase reliability or decrease prices if additional pipeline is needed? I'm not really convinced that the retail choice programs are the proper analogue for this, but I'm open to suggestions. Who pays for the pipeline capacity and how do we get allocated to the generators via reliability mechanism?

That being said, the only issue before the Commission in this docket is whether the proposed tariff modifications to provide Algonquin with a waiver of capacity release rules is necessary.

Calpine believes, our experience has demonstrated that the missing tools provided by capacity release and the template provided via Order 712 are more than adequate to address any concerns raised by Algonquin, and by inference, the electric distribution companies. The existing rules provide a liquid and transparent market for pipeline capacity with broad participation.

The rules as they exist now are non-discriminatory. They have a well-established record of functionality and involved industry-wide standards. This labor would impede the performance of a market if all energy engaged, even tangentially, in the remaining gas supply. These were not a barrier to construction in new pipeline projects. These projects must stand on their own economic merits, none of the many pipeline projects implemented or proposed recently, including the Algonquin projects that have already entered construction or have been built.

A pipeline proposed built without this proposed waiver would mitigate pipeline constraints, therefore, reducing basic differentials and price volatility. This waiver is therefore not needed to provide benefits to electric customers. Further, the proposed capacity would be available only to a subset of mutual generators, those who would be served directly by

Algonquin. This would clearly establish a significant price disparity between generators served by Algonquin and that goes to other regional pipeline or directly by LNG. This is inconsistent with the manner in which prices are formed in a uniform cleared power market.

In summary, Calpine believes strongly that labor should be rejected. We are happy to confer with Algonquin, the electric distribution companies, or any other interested party to discuss the dynamics of the fuel procurement in the East and explore ways to further improve the tools we all use to provide reliable and cost-effective gas power from New England.

I thank you for your time.

MS. FERNANDEZ: Thank you, Craig.

Next, we have Joe Dalton from ENGIE.

MR. DALTON: Joe Dalton, ENGIE Gas and LNG. Commissioner and staff, thank for the opportunity to let us share thoughts of ENGIE with you on this issue today. Like Mr. Coyle, I do not have a prepared presentation. Like Mr. Coyle, some of his very legitimate points are very similar to the points that I was going to raise, so that will reduce the time that I will need to make this presentation as well.

What I thought I would do was just a little bit of background on ENGIE and how we came to be interested

in this topic, a little bit of additional color on one of our principal concerns which is that this is premature. And then our view of the capacity release program generally.

So ENGIE gas and LNG imports liquefied natural gas into the import terminal up in Massachusetts. For gas that pre-gasified or vaporized gas and liquid, and we can do that simultaneously. We have 3.4 BCF of storage onsite. Our install re-gasification capacity is 1 BCF a day, and we can do 100 trucks for 100,000 mmBPU's. Our maximum single day send out to the Algonquin system is in excess of 276,000. Our maximum delivery day to the system is in excess of 737,000 mmBPU's.

We can process 210 BCF of LNG per annum. We connect directly into the two existing interstate natural gas systems serving New England, the Tennessee system, and the Algonquin system. We also directly connect into National Grid's distribution system to the Boston gas system, and we have a direct connection to the Exelon Mystic Power Station. And we serve this systems, as has been discussed, moving gas from east to west, so on a back-haul basis. So that's a wrinkle in the discussion of constraints that are coming into the system. We can actually move gas into that direction. And on peak days we tend to be able to move more of it on a back-haul basis.

And our send-out can be varied from an hourly rate from zero to 31,000 mmBPU's per hour, and we can also back a no notice service out of our facility.

So we have kind of unique capabilities. The back-haul access to the system gives us a perspective where we have a great deal of concern about the fact that this request to serve similar customers with similar needs in a highly preferential way reduces our ability to serve those same customers and reduces our market. With respect to the notion that this is a premature issue, I would note that in addition to the filings Mr. Coyle referenced, there is also yet to be introduced a request for proposals from the Department of Energy and Environmental Protection in Connecticut or the Public Regulatory Authority. So Connecticut has yet to enter into discussions on the issue. But the characterization that states in determining how much of this capacity they want is also premature. The very legality of whether or not they can access this program is at stake.

In New Hampshire, for instance, in the order issuing in the New Hampshire PNC Order 25860 issued on January 19th, the Commission, and I quote, said: "It is clear to the Commission from a review of the staff reports, stakeholder comments, and ancillary materials made publicly available through this investigation that no consensus

exists regarding the potential legality of such an acquisition of gas capacity by New Hampshire EDC." And then goes on to say that they would bifurcate the process and in describing the first phase of the process, the Commission would review briefs submitted by the petitioner EDC, staff, and other parties, regarding whether such capacity procurement is allowed under New Hampshire law. If the Commission were to rule against the legality of such acquisition, the petition would be dismissed.

So when we talk about this issue being premature, it's not really in the abstract. And as Mr. Coyle referenced just last Thursday at the Supreme Judicial Court, there was a very active litigation occurring with respect to whether or not, in fact, the Massachusetts Department of Public Utilities has the authority under existing laws and in exercise of that authority would be consistent with the Restructuring Act to have sustained its assertion of its authority under those provisions.

So again, I would just note that I don't think these are abstract concepts. These are important considerations for you in your deliberations on this matter.

And the final thing I would say I think on this is just that -- as an entity that moves natural gas

over these pipes on a back-haul basis to serve the same customers as being contemplated in this request, we feel pretty strongly that special access provided through this waiver to subsidized capacity is not good for consumers, is not good for a well functioning market, and is not good for participants like ENGIE that rely on fair and impartial treatment as participants in these markets. And I've intentionally kept it brief so that we can stay on target.

Thank you for your time.

MS. FERNANDEZ: Thank you, Joe.

Next, we have Kathleen Barron from Exelon.

MS. BARRON: Thank you. We do appreciate the Commission scheduling this conference. And I think one of the reasons that it's important is because this has been portrayed as sort of a one-off kind of thing, it's limited its target, it's narrow. But if it is approved here, it is a reflection that is can be approved across the country as more gas generation comes on line. So it's very important to do what you're doing here today and dig into what are the details and is it really necessary?

I'm here on behalf of Exelon. Like Calpine, a major generator in the U.S., also a major utility company in the U.S. In New England, we have 2,500 megawatts of generation, we're a major competitive retailer serving loads and a significant gas marketer.

I'm going to address two issues, one is the narrow issue of the waiver itself, whether it's justified on this record; and then more broadly, I'll say a few things about the potential underlying state programs and how they could affect both the market -- and I think conflated those two topics and I'd like to keep them separate.

On the issue of the waiver, I think it is a very, very narrow question for you. If the waiver is not, it's not going to stop the pipeline expansion. According to the EDC and the statements they made in the state proceedings, they will go ahead with or without the waiver. The programs that you heard are not yet finalized, so therefore there is no condition in the state program to have this waiver in place. In the Massachusetts case in particular, there was a motion to stay filed in that case pending the outcome of this case. And in response, both National Grid and Eversource said that although the discriminatory releases are preferred, they're not required for them to invest in the pipeline explanation.

So in our view that means there is no exigency to this situation that requires a Commission to display what its policy has been for a long time and policy that worked quite hard to develop. It's also notable that there are no states in the docket asking for the labor while they

sort out the legality of their state programs they easily could have come in and asked the Commission to grant the waiver in the event that the state programs go forward. None of them did that. The only thing the state represented here is telling you to stop.

So I think that's an important point to acknowledge as well. So in our view, there has been no reason presented to change the policy now. When the Commission has looked at changing its capacity release, it has done so using a rulemaking process with a whole lot of attention to the details of the program being examined and sorted out over a long period of time. That has not happened here.

And so our view is that the waiver should be rejected and that the state programs should continue to proceed in the state commissions. And if there is a need for the waiver down the road after the details have been sorted out, then the companies can re-file for it.

As I said, I also would like to take a few minutes to talk about the potential state programs and offer a few points about how to think about their effect on the wholesale market. The Commission isn't doing anything about the state programs of course. It's more than just a waiver question. But it is, I think, relevant to start to think about that. The first point is that the premise of

the program seems to be that electric generators are not going to buy expensive firm transport.

I think Anna, your question got to this directly, this is not a question of timing of mechanics, this is one of price. And the point is it is too expensive, we should make it less expensive by having the EDC's customers pay the capacity in running the generators at a deeply discounted price. So let's test that.

What do we know about what gas ultimately will contract for firm capacity? We heard a lot today about the multiple types of options that are available to customers -- generators to obtain firm delivery from marketers. Pay-for-performance has not taken effect yet, so we don't have sufficient data to know whether that program will incentivize gas generators to sign up. The only thing I think we do know is that to the extent there is a waiver granted here that they most likely are not going to sign up, because if they think there's going to be below-market capacity available from EDC's then they'll wait to see what that looks like.

If we were to conclude, however, that gas generators are not sufficiently investing in firm transport and we simultaneously think that there should be more investment in pipeline expansion even after the Access Northeast is complete, then what should we do about that?

And it seems to me that there are a couple of options, and I thought I'd use the language Chairman Bay used in his descent of the PJM capacity performance base, as you might be very familiar with. He talked about things from the perspective of carrots and sticks.

So we could create a carrot or two, or we create a stick or two, or we could do both. And so this really takes you to question of what's going on in the electric markets that could change that incentive about the generators. And there's two points to make here, one is in the capacity market side where currently there is no way to recover from capacity costs for gas transportation capacity costs in the electric capacity market. Both costs would not be included in a bid selected to a pipeline now and want to contract for firm capacity. And likewise, because of the nature of the energy market, there's no opportunity to recover in the energy market firm capacity cost generators are required, they're variable costs there, so an investment in firm transport is not able to be reflected in an energy bid. Those two things could be changed or one of them could be changed in the nature of a carrot, in the nature of a stick. Of course, I know as Mr. Daly pointed out, we have very significant performance penalties that will take effect in 2018. Those penalties could be increased if the Commission or the ISO or other market

participants think they were not sufficient, they could go up.

But the point here is if the electric rules, if there's a problem with them we should address the problem with the electric rules, not create exceptions to the gas rules. One of the points, the point of course of pay-per-performance, was to put the risk of non-performance on generators on customers, and the state programs sort of flipped that and put the cost of the pipeline expansion on customers instead.

The second point is that the effect on the market of pushing through new pipeline capacity if there isn't sufficient interest on the part of the parties investing in that capacity of price is necessary so that it is significant. We've operated this market on the understanding that a price signal for a new capacity is going to reveal itself when it's necessary, and if there is no price signal then you shouldn't be investing but subsidizing the capacity. I heard Commissioner LaFleur compare this as sort of the methadone clinic of subsidy arguments, once you subsidize one pipeline or one infrastructure, then there won't be merchant investment the next time around without another subsidy and that's the case here.

Given that the under-recoveries of the

expansion will be recovered from customers, the EDC's do not have the same incentive to demand the highest possible price, hence they are asking for a waiver to allow generators to pay less. And cognitive of this reality, generators in turn have little incentive to offer for the capacity because they're sheltered from competing in the market from other market participants.

And another point is that the discriminatory release rules, since they bar generated from rereleasing the capacity as we have discussed this morning, that could further depress the price because the generators don't have any recourse of reselling that capacity, so they're not going to have an incentive to bid very high for it.

We also wanted to note, and this is reflected in the record, that building more pipeline subsidies is going to undermine the diversity of the marketplace. It can target for existing base load state of the market, new LNG sources to come. Here we always talk about wanting to decrease over reliance on natural gas generation, but by providing such a strong advantage here, this will push others out of the market. At the moment, we have 9 gigawatts and growing to 11 gigawatts of dual fuel capacity. We have had lowest energy price year last year since competition began. These were all -- if you look at it from that perspective -- good developments, we're going

in the right direction, and we want to keep that push going. And despite all of that, there actually is investment in pipeline capacity we've talked about today, we're not seeing any in this waiver to achieve it, but Algonquin is developing a couple of projects, Connecticut expansion is in development. So it's not true that we don't have any market signals for new capacity coming in.

The last point is really just the bigger picture going back to the basic strategy of the state programs in thinking that firm transport is too expensive and trying to make that cheaper. To state the obvious, these programs are not the only attempts by states to change the economics of the markets they care about. Commission has stated this issue in a number of jurisdictions in Ohio, Maryland and New Jersey. When there is an attempt like this to change a market design that the Commission has approved its market redesign, but when the Commission has already taken a number of steps in the winter reliability program, its gas generator fuel policy is a good reason to let those policies work and not second-guess them.

So I look forward to questions.

MS. FERNANDEZ: Thanks, Kathleen.

Next, we have Vince Morrissette.

MR. MORRISSETTE: We've got handouts, too, if whoever wants a paper copy of it, we'll have some.

Thank you, Commission, for allowing us to be here today and express Repsol's concerns and express our opinions on the proposed gas release and the EDC's. I'm going to go through this fairly quickly; I know I can get through it under 15 minutes. Some of the information has already been covered. But anyway, here we go.

Proceed straight to slide 4. I'm going to give you a background on what Repsol's position is in the Northeast U.S. and why we're interested in this issue. Repsol owns all the capacity at the Canon Port LNG area and St. John and New Brunswick and BCF capacity. The facility has 10 BCF of storage. We have 730,000 capacity of gas through Maritime's pipeline into Algonquin and Tennessee. We have been in service since 2009, have been actively trading in the region since 2008. The peak send out today of about 950,000 decaterms a day. We also, last year, implemented a power-trading group, and we are currently tolling at these plants in the New England region, with a vest interest in power trader and gas in that region.

Just to talk specifically about the past utilization on AGC: AGC currently has west-to-east capacity of approximately 1,350 decaterms a day. The only fees we've heard on vast majority of that capacity, and always have, they utilize all of that capacity on peak winter days during the rest of the season primarily in the

summer when demand is low they only utilize about 20 to 30 percent of that. So you can have in excess of 1,000 decaterms a day of capacity available for the discretionary markets which is primarily power, so keep these numbers in mind.

On peak winter days, the market relies on back-feed supply for these discretionary markets, primarily once again Power Gen. So every LNG, Canon Port LNG, Portland Natural Gas, other indigenous supply on Maritime that support the Northeast Gateway offshore facility. And all of those sources have been very successful over the last several years, peak demand providing supply to the market in lieu of existing BCF and aggregate in many situations.

With respect to capacity growth on Algonquin, talking about how much capacity is needed, currently have the aim project under construction, that it's going to bring 300.2 a day of new capacity on Algonquin. The Atlantic Bridge project is under review, that's 136,000; once again, both of those are primarily supported by the LDC's. I think both of those will certainly go into service. That's a total of 478,000 a day of new capacity with the, of course, ANE project with another 900,000 on top of that.

As we've heard in the current forward-capacity

market auctions, there's been about 2,300 megawatts that have cleared through the current auction -- I have "2,700" there, I think that's a typo. But anyway, that represents about 500,000 dekatherms a day of demand if all of those units peaked at once.

So given this, you've got 407,000 a day of new capacity coming, it's going to be already added to the system. You've got very, very limited growth potential in the overall electricity market. Granted, gas has taken a bigger portion of that, but I don't know how long it will continue to grow at that pace. It seems like the primary impact of ANE will be to create a lot of additional excess, unutilized expensive capacity that's going to diminish the value of the existing capacity on Algonquin. And that's where the capacity release rules really come into play.

You've already seen this graph, once again the 900,000 represents about 5,000 megawatts of aggregation areas that they could find. Going to the next page, and this is really the crux of my presentation, this page shows the actual innovate nominations on Algonquin going back five years, five years, five winters essentially. The band in red there at the bottom, that represents the residential, commercial industrial demand, primarily the LDC load. The grand power generation was -- the first sold red line represents that 1,350,000 of capacity on

Algonquin. When you go beyond that line you are exceeding the capacity, you see the squiggly black line above that, that represents those back-feed supply sources feeding the system. Then I've superimposed the expansion projects on there. The first dotted line, the blue dotted line, represents the AIM project, 342,000 a day; next 136,000 of the Atlantic Bridge project, that's the orange dotted line; and finally you go to the top dotted green line, that represents that ANE capacity. The shaded red area is right below the red line, that's the available capacity that is currently unutilized during the summer.

Granted, during the summer they have maintenance outages and other things on a short-term basis to limit their capacity. But overall that shows the available capacity. If you'll note on the green there, the max power gen load in the summer has been somewhere between 700,000 and 800,000 a day on a peak basis. Keep in mind once again we're adding 900,000 and proposing that 900,000 give them preferential right to capacity release. That's very significant.

In the winter once again the back feed supply sources are able to compensate for that. And you've got the additional 486,000 a day of new capacity coming on line. So I think, number 1, it's premature to provide this exemption, getting the cart way ahead of the horse, as far

as where the Access Northeast project is in its current state of development. And then, number 2, at the very least, that would diminish the capacity or the value of that existing capacity on the system.

Going on to slide 9, this is looking at the current spread between Central N3 and ADC which represents the market value on capacity of Algonquin. The N3 prices is essentially that price at Lambertville where gas comes into the farthest western inlet to Algonquin, and of course the Algonquin price represents the market price in Algonquin. So you're looking at an average basis, if you will, of 88 cents per decaterm from 2008 and on. Solving an 88-cent problem with probably at least two dollars worth of capacity doesn't seem to be the best economic decision. And also putting all this additional capacity in the market is supposed to of course reduce that basis, which would reduce the value by that capacity obviously.

So it begs the question once again: If that goes forward and if those results happen, why do you need a preferential capacity release mechanism for the EDC capacity holders? Why isn't it just thrown in with the same trunks with all of the other available capacity on the system?

Going on to slide 10, and I've covered a few of these. But once again, the pros of exemption for the EDC's

gives the New England preference over the existing capacity on ADC which certainly is keeping the value of that. Key questions are whether or not generators will be caused to take assignment of the more expensive aid in the capacity in lieu of that what's available in the current market. In other words, like I showed earlier, you got that peak of about 700, 800,000 a day in the summer, that represents all of the demand on ADT power gen, that will grow a little bit or maybe significantly, regardless there's plenty of capacity there for it. So for those generators, instead of going to the open market and getting that capacity that's existing today, are they going to be forced to utilize that next prong that ANE capacity or the Access Northeast capacity at a higher price? Why aren't they just thrown in the same pool of capacity and let the market once again determine which capacity gets released to them and at what price?

It's hard to envision a scenario given the excessive amount of capacities being added where actually the generators relieve that much capacity of the market, in general will need that much capacity for the foreseeable future.

Finally, going on to slide 11, some brief conclusions . Since you have ample capacity that exists to serve the discretionary markets if Access Northeast is

implemented, the EDC's that hold this capacity should certainly be subject to the same capacity release rules as all of the other capacity holders. The proposed EDC capacity release exemption appears to enhance the subsidization of the EDC's in the current capacity holders, which is primarily the LDC's since capacity will not be released via competitive market-based mechanism or at least there's not enough definition around it today to determine that.

The capacity release mechanism also essentially eliminates cost-effective peak day gas required from the markets, that would be the LNG supplier, the back-feed suppliers if you will, which, in turn, could increase the overall cost of the electricity to the market.

Finally, competitive and transparent markets are the foundation of New England's gas and electric markets. So giving any party preferential treatment in the capacity release market will disrupt the open-market process.

And those are my comments. Thank you again for allowing us to speak today.

MS. FERNANDEZ: Thank you, Vince.

Our last presentation is Tom Lockett with Tenaska.

MR. LOCKETT: Thank you very much for the

opportunity to speak today. It's greatly appreciated, thank you.

I'll tell you a little bit about Tenaska, I know we're time deprived a little bit so I'll move quickly through those first two slides.

First off, Tenaska is about the fifth largest marketer in North America. We have about 8 BCF a day, we hold transportation in over 30 inter- and intrastate pipelines. We manage about 125 BCF of storage. We trade with in excess of 740 counterparties, and we have last year about 162,000 transactions. It's very important to notice that most of those transactions today had transactions, but a very large percentage -- and I don't know the number, but a very large percentage -- are intraday going through those various power gen-type cycles of late nominations, not day-ahead.

In terms of Tenaska marketing ventures specifically, we manage in -- we're not a trading shop, we're a physical supply chain management company; it's very important to notice that because we're not out there trading. We manage customer transport in accordance with FERC Order 712, we're both generators and LDC's and industrials.

We maximize the asset optimization value for these customers and we pay them a large amount of money for

the right to do that. And that money, especially when it comes to LDC's, imitates what we believe to be EDC's, does have the ability to trickle down to the ratepayer.

We own and operate about 6.7 gigawatts of power generation that is ours, under our control and ownership. And we manage an additional 16.3 gigawatts of third-party generation. So we're very familiar with the generation market.

So this slide is only two bullets but it's actually very, very important. Tenaska is neutral on the plan EDC-supported pipeline expansion project. Let me restate that: Tenaska is agnostic as to whether or not we put incremental steel in the ground or not. What we do have an issue with is the proposed exemptions from the Commission's capacity released regulations. These regulations are well-established and work fine; if it isn't broken, it doesn't need to be fixed in our opinion.

We believe the proposed exemption is premature, it's unnecessary in result of construction on both competition and reduced market efficiency. The electric reliability service programs have not been approved by the state regulators and the EDC's have acknowledged that the benefits of proposed pipeline conduct will still be realized even absent these proposed restrictions. It's a very, very important take-away here.

The ratepayer will still receive lower power cost, the economy will get a benefit in that regard without these pipeline rerelease restrictions. Based on our limited details to date, a number of questions have been asked -- I realize things are still evolving -- but based on the information that we where is obtained, the capacity will only be releasable to power generators or held by the EDC's themselves. Power generators, and we've talked to a lot, power generations whose core business is converting gas to electricity cannot rerelease to an optimizer and cannot sell to third-party marketers in an off-peak period; again, that's our understanding on the details to date. But if you looked at a hypothetical scenario and not unrealistic where a power generator-combined cycle is burning five by 16, meaning Monday through Friday 16 hours a day on peak, and those off peak-hours including Saturday and Sunday and holidays that that gas would not be available to hold up gas markets.

How ironic would that be on a 10 degree Fahrenheit day of 50 degree day and that gas would not be available to other gas customers who might need it. Proposed tariffs limit access competition transparency: They're inflexible. We believe that they may have restrictions on segmentation, on our receipt point access, and in general, like I just described, third-party sales

transactions.

Power generators cannot reallocate capacity even if the suppliers are not available, the primary point of the uneconomic if other cheaper, say, mid-month points of receipt gas, supply gas, come to bear, or if the gas prices that they're burning exceed their ultimate fuel, the capacity has to be used. This is based on the limited information that we've heard, we've been told but it seems like a very inflexible proposal.

If you look at this slide, it's a little complex but it's really not. It's the Algonquin system. It's the entire system. It goes up to the Boston area, say 10,000 decaterms just for example, you could do segmentation, the economic and operational efficiency, you could break that into various pieces and make sales of 30-, 40-, 50,000 mmBPU's of capacity with 10,000 mmBPU's total. That's a very effective, cost effective, use of utilization of that capacity. Who benefits? The ratepayer benefits. Because in most cases this capacity is being provided by an LDC, that LDC is being paid well through an asset management arrangement, and many of those dollars, depends on which state you're in, trickle down to the ratepayer.

Under the proposed tariff the restriction optimization would reduce the value to the ratepayer. You can see in this case it goes from one point to one point,

from a receipt point from a power gen without any of that secondary market optimization; the ratepayer suffers.

In conclusion, we think that the filing should be rejected. There's no justification for this exemption. When and if the electric reliability supply plans get developed by the states, we can come back and reexplore this and re-discuss this. But also the burden must be on the pipeline to establish the need for waiver, and we don't feel that's been effectively presented. Thank you, I look forward to your questions.

MS. FERNANDEZ: Thanks, Tom.

And now we're going to open it up to questions.

First, does Commissioner LaFleur have any questions?

COMMISSIONER LaFLEUR: Well, thank you. I do have a couple questions that have been nagging at me that I'll try to frame as a question.

Mr. Coyle, thank you for saying that you agree that the electric and gas markets are working. I'm a huge believer that markets are a good way to attract and allocate resources to serve customers. There's been a thing, a sentence that's been repeated so many times, I've even said it myself a burp of times, that there's a structural issue between the gas and the electric market was the theory, that the gas market are really not

attracting investment with people making 10- to 15-year confidence in the electric market, only day-ahead, three-year-ahead capacity awardance with structural disconnect. And this big, new customer of natural gas, the generation industry, bearing in mind that these green lines grow a lot when some of the plans that are no longer burning natural gas are no longer in New England, the bug, new customer is given. So who's going to step up and make them is the debate that's gone around and around? And the ISO is going to put up the money, and that was the EDC's, that's the latest idea that the EDC's are going to put up the money. And the concept of this whole debate is that the generators would say, "My God, this is awesome, we don't have to put up the money, someone's putting up the money. This is great."

So I guess, Mr. Adams, you're in the unlucky position of really being the only pure gas generator here. The electric customers are stepping forward, at least in this proposal, to help build a pipeline to make these lines go up so there'd be more gas in New England.

MR. ADAMS: Yes.

COMMISSIONER LaFLEUR: In and of itself, is that good for the generators? Do you propose the project? Mr. Lockett said he was agnostic, I mean I don't mean to cite him or whatever. But the idea of the structure, is it

just the waiver that you oppose, the exemption, or is there some way they could protect their customers that you could live with? Because the generators are missing in this debate as a source. They're the ones they're supposed to be all for.

So I'm interested if you could tease out your view as little more of if you think there is that disconnect and someone has to step up and build pipelines? And if so, is it just this specific proposal that's before us? Is there any way we can work through this? Sorry that you don't have a bunch of other pure generators next to you who don't also sell gas to answer it.

MR. ADAMS: We have a unique role in this space, which is why I'm glad that I was allowed to participate. I agree with Tom Lockett that we're agnostic as to whether Access Northeast gets built or not. The waiver in and of itself concerns me because, again, the existing tools we have to manage secondary capacity work and they work well. I don't think this waiver is needed to incent/to promote the price signal to get built. And you're right, you would think that at its core generators like Calpine, all other things being equal, would be in support of the capacity. The problem is the capacity only solves one leg of the puzzle.

As I mentioned before in my question to

Mr. Kruse, I have a question about where we buy gas when? That's a tactical problem that can easily be addressed but it's something to think about. But at the end of the day I don't really see how the purchase of pipeline capacity by the EDC's translates directly into customer relief for the electric ratepayers. Now, if this were part of a more comprehensive structure that was where an EDC desired to purchase some block of power from Calpine for a certain period of time, then perhaps we could justify the capacity in and of itself. But right now this has the capability of being a nontransparent addition to the marketplace and just a complication in the market that, although it has its warts and pimples, the market seems to work relatively now under the structure right now.

COMMISSIONER LaFLEUR: All right, thank you. And the idea of buying a hunk from Calpine and then having to get -- that would be kind of honest re-regulation. Right?

MR. ADAMS: Exactly. And that's another concern that I have with it. There's a whole lot of stuff going on here that strikes me as being good from one perspective but being damaging to the evolution of the deregulated ISO-driven market on another. So I fully understand the price signals that the pipelines seek to receive. I spent the first part of my career at Transco and I proudly refer

to myself as a recovering pipelayer. And then I've spent some time at LNG land, I spent some time managing access for all the facilities here, bought a plant from Kathleen. So I've got all sorts of different angles to come at this from. But at the end of the day the market we have works, I will point out that even during the polar vortex the lights stay on. I will not disagree that the prices were extraordinary. I'll point out that the people who received, the parties that received the windfalls in that case were the people who held pipeline capacity, not the generators. Generators like Calpine that have a capacity supply obligation from the ISO, we have some latitude as to how we bid in the units and what prices we pay for fuel, but if we get out of whack with our reference price then we get mitigated.

So despite some of the things I've heard and read particularly in the New England press, we're not reaping windfalls here. Please look at our stock price. We just want a level playing field that allows us to compete heads' up with looking at things through our own particular lens.

COMMISSIONER LaFLEUR: Thank you. Turning to something that might be a little easier, if anything is in this space. I want to tease out a little more the argument that several people have made that it's premature for the

Commission to act. We seem to have a lot of situations where a state commission is looking at some aspect of a problem and we're looking at another aspect of a problem, or sometimes the same aspect of the problem from a different lens, and we're being told to act or don't act or wait for them or don't wait for them. And I am a little worried that we get in a loop until we don't want to act until we hear from the states and they don't want to act until they hear from us. So for those of who you that think it is premature for us to act, how would you have it play out? Should we wait until the state proceedings are over? And do you think they're going to be looking up at us? Or should we just kind of close the docket in advance until the states have said something? Because that's always a little bit of a -- you can get a little bit of a chicken and an egg.

Thank you.

MR. DALY: May I? Since some of the entities that are here, just to put it on the table, some of the entities are arguing for delay are the same ones that are intervening in our State proceedings and telling the states that it's premature to operate there either because FERC has an egg. So they're shaping up this do-nothing loop I think it is. And that's inappropriate. I think, and what we need is the agency that has jurisdiction to take action

in an appropriate timeframe, that it needs to do it and have considered debate like this here, but then take action so we can move forward. The difficulty with the New England states in particular is they have six different jurisdictions. And I find a good dynamic is, if one moves, the others will start to move as well. And somebody needs to take a leadership position, and then they do tend to get in line. So I do think there's that opportunity. I think if FERC can opine on this and get that out of the way, we have some definition on the solution, and I would urge the FERC to do just that.

MS. BARRON: I think that our recommendation, as I said, is to reject it. In this circumstance it's not necessary for the extension of the program and it's not clear that the program's going to be approved. If they get approved and if there is a situation in the future where the pipelines want to re-urge the request for the waiver, then our position is it should be done on an industry-wide basis, that it's too important to just do it on a one-off basis. And that if you're going to consider an exemption of this magnitude that you should do it under sort of the considered process when we do the AMA.

MR. ADAMS: Can I follow up on that real quick? From Calpine's perspective -- and, again, given the long history that we professionally have with managing assets --

the entire construct of capacity being released through the jurisdictional process in tiny bite-sized pieces for tiny bite sizes of the day is too clunky, it won't work. The best way for this process to get to, to go from the EDC's and to the generators, is through Order 712 asset management structure. That is designed to handle processes like this, and it works seamlessly. So we think strongly that 712 is the ideal tool for this, and as a result it's not a question of acting on the waiver prematurely, it's a question of the waiver being necessary at all.

COMMISSIONER LaFLEUR: I know Mr. Coyle has been trying to say something.

MR. COYLE: Just two points in my response. The first one is that your pipeline release regulations work. We've heard that point before. There isn't an deficiency in the price signal, okay. To the extent that you were to entertain this proposal at all, and to get to your real question what should be do about it, I think the correct answer in context is you should reject this proposal without prejudice because if you're writing a blank check in substance for state programs that don't exist, those programs may or may not come forth on the basis of that blank check and you'll all of a sudden find yourself in a space where I have found myself somewhat uncomfortable with an amicus briefing in Hughes versus Talon Energy. There's

a preemption issue down the road to the extent that the State programs interfere with the Commission's capacity release mechanisms, which is one of the you preferred and I think effective tools.

So the place to let it start, if it's going to start, is to have a fully developed state program if the states really want to shackle retail electric customers to pipeline connection. As the State Commission, he can pronounce that if that's what they want to do. Again, I think, as I've come to understand this Commission's perspective talking about agnosticism, that's a value judgment that you can make at a state level. If they can find a way to make it work for their constituencies, great, bring it here. Then you can thrash out the extent to which there is a preemption problem. We've got the cart way before the horse here the way it's been presented.

MR. RUDIAK: And just to be clear, as with some of the others have said, we think this is a bad idea. We think it's unduly discriminatory and sets up a weighted preference in an unhealthy way. We also think it's helpful to have an appreciation that it's not a -- the notion of what's happening in the states isn't just how much do they want, it's can they even do it. So it's a data point. Would action here help clear some of that? Sure. I think the overhang of what happens next, it's paralysis of

analysis to a certain extent. Everyone's waiting to see if there's going to be some huge subsidy going in the mix, and as a consequence maybe that's what's impeding otherwise market-based development with these projects.

So to the extent, it's helpful to provide some clarity in this regard, but that may be useful in the context of those other deliberations. But it's also important to take note that they're happening and that there's a big question that all of those individual states are dealing with as well.

COMMISSIONER LaFLEUR: Thank you all. I appreciate the specificity of your suggestions.

Anna?

MS. FERNANDEZ: Richard, did you want to state something?

MR. KRUSE: Just a different perspective, I think, deferring these questions, length or state of action that need developed. We're on a multitrack state, federal regulatory approval process as we speak. And if you wait until the state crafts it, then you bring it. If it's not constructed the way you want it to be constructed, you've set the project back six, -seven months, because all of a sudden we're going back to the states, we're going back through the analysis. Is the state willing to approve this program?

So if there's elements of this program based on the comments today, we certainly have heard a lot of diverse use regarding the appropriateness of it. But if there's elements of this that is acceptable to the Commission subject to tweaks, it will help the process. It will help the debate at the state level, even for that matter ultimately here at the Commission again for us to know what are the limits that we can go in this area because the EDC's are trying to figure out how to protect their retail customers. And the one thing I would submit that is abundantly clear is that the infrastructure is constrained on a west-east basis. Certainly, there are options from the east and they play a vital role currently. But to the extent the marketplace want to access lower cost to policy, go ahead, there are constraints. And those constraints are resulting in an outcome that is inefficient from the consumers. The consumers are paying more for the electricity than what the EDC's, based on their studies where they need to if we had had that infrastructure. So ultimately the consumers are being hurt by this delay. So if you have got it, we welcome it. If we can tweak it to address the Commission's concern, we think Algonquin as well as the EDC's are eager to hear those tweaks. But we need some guidance from the Commission as soon as possible.

MS. FERNANDEZ: Any staff questions?

MR. GOLDENBERG: I have a question. On the gas side, when I first started working here the local distribution company had bought all the gas, there were no retail marketers, and as much gas as the state you see authorized they were allowed to buy. And then when retail marketing started on the state level, we crafted an exemption to keep that same capacity within the State. And I'm not sure why this is any different where various New England states, the EDC's if they were vertically-integrated, they could have pot this capacity and used it for themselves. Now they're forced to unbundle. On the gas side, is this any different than it is on the retail access side and a local distribution company. I don't think people have really talked about that very much.

MR. BRENNAN: I guess I was going to say it does confuse the issue a bit because the generators unable to make those long-term commitments that either a vertically-integrated utility would have made. The generators we know, making it for various reasons, are not willing to or able to. They may potentially be able to recover some of these costs, at least if they're a new resource, in the forward capacity market. There is some indexing, a lot of the transportation daily and the western side of the energy market. But that long-term commitment

is missing.

So what we have here is the EDC's, due to their reliability in pricing concerns for the markets that are affecting their customers, are the ones stepping forward saying, "We can do what can normally be done." And all what we're really asking, if you think this through, we do this a slightly different way: Allow us that opportunity to use it for the purpose it was purchased primarily; to the extent we don't need it for that purpose, we will release it in the normal capacity load. It's just that we're in the middle of being the first to make it available to the generators on a targeted basis because we have an extra step in the middle there due to the way these markets have turned out and the lack of anyone else being able to step up directly to solve the reliability and pricing concerns. Those concerns are real. The generators can say the lights haven't gone out, but -- and they may not in the near term, but we have 4,000 megawatts that will be retiring within the next five years, we have another 6,000 that will potentially be retiring.

We look at the Internet connection queue of 8,000 megawatts of resources, gas-fired, the others are renewables which will require more gas to back them up. So the definition of "reliability" isn't right now whether the lights go out the capacity lingers, but if you even switch

to dual fuel capability and all of a sudden you lose both a generator and a transmission or maybe some hydro from the north stops flowing because of the issue of the winter in Canada, that's a reliability concern and that's what we should be protecting as with additional infrastructure of gas. It's not enough to say there's no reliability or problem because the lights haven't gone out so far.

MR. DALY: But it's exactly analogous to the LDC's situation where the LDC's are allocating their capacity to their in-use customers. In this case, the EDC's are allocating the capacity to power generators who are the customers that serve the electric load. So it's quite analogous in our view. There was talk of having the LDC's contract for their capacity, and some people have even said that. I believe Mr. Coyle's client has said that. But we saw a closer link between the EDC's, their customers, and the power generators to do it through that route rather than the LDC route. But that looked like a more justifiable expenditure on behalf of electric customers than bringing in the LDC customers who wouldn't really have the same alignment of interest, should I call it. But I see it as very analogous.

MS. BARRON: I think your question highlights why this is so important. We made this decision to unbundle to have competition. The assumption is that the

generator is going to incur the cost that it needs to to be able to meet its capacity obligations at the least possible price. And right now they're telling you they don't need to buy firm capacity from Algonquin as they can use the products that are in the market already, and they're investing in dual fuel, I mean, that is the technology that's coming in through the capacity market, not even happened at the last auction. So we're getting competitive generation coming and they can use oil during the powers as needed when the gas prices reflect the flow, and that's the economic choice made on behalf of the market. And that's the model that the Commission and the states chose. So if we're going to shift to a different model, we have to open up a broader conversation, as Craig said. But it's not that they're not interested in it, it's not economic potentially.

MR. COYLE: Charlie Monger's first rule: Make sure you understand what the incentives are and that they're correctly aligned, okay. The difference between allowing the LDC's to reclaim the pipe capacity in the context of their retail access program, where you have a consistent function across the industry is a whole lot different than saying, "I'm going to make electric retail customers pay for gas pipe," which we're then going to somehow figure out how to manage when the people who

produce the electricity are saying, "We don't need it." And to say, "Well, okay, maybe we're just going to partially rely on market price signals in this context" is crazy. You're undertaking in substance a partial vertical reintegration. And it really doesn't make a great deal of sense because the ultimate end user, the merchant generator, is saying, I don't need it, I will let you know if I do but I don't right now. And your statutory mandate under the Natural Gas Act requires you to some extent to rely on a market price signal for facilities explanation.

MR. GOLDENBERG: Isn't that similar to the fact that retail access programs on the gas side, the LDC contracts for the capacity, they just hand it out to the marketers, they don't even go so far as to have the various marketers bid for the capacity. They just hand it out to the marketers in proportion to their retail customers and the marketers compete solely on the basis of gas prices. At least in this case, the EDC's are at least proposing to release the capacity to the generators who bid the highest. So it seems like that's an improvement over the retail access program in a sense.

MR. COYLE: I don't think so. There's a significant difference on the facility can measure demand on its system. And the acuity with which electric distribution companies can calculate the gas capacity

that's required to support merchant generation. You want the difference in a nutshell, I think that's it.

MR. GOLDENBERG: I have a question for Tenaska. Do you sell firm gas to generators? And if so, what kind of capacity do you have to require in order to provide that service?

MR. LOCKETT: Yes, the answer is yes, we do sell to generators. And it would be a capacity required to an asset management arrangement with that generator or potentially with an LDC or potentially something that we'll bid on separately in the market just through the electronic bulletin board. We're not really making those deliveries with interruptible transportation at all.

MR. GOLDENBERG: Do you have your own firm contract going on there?

MR. LOCKETT: No, we do not. No.

MR. GOLDENBERG: Were you interested in any of these projects by Algonquin? Did you see a need to supply firm gas to generators that you needed firm transformation on Algonquin?

MR. LOCKETT: Let me see if I can rephrase the question. Was the question: Was Tenaska interested in entering into proceeding agreements to buy capacity itself?

MR. GOLDENBERG: Yeah.

MR. LOCKETT: It's an interesting thought. The

capital investment in term is way outside of our risk tolerance. In 20-year terms, I would presume, in looking at very, very large demand charges, and way outside the ability to hedge any of those spreads. So we would not have the risk appetite for this scale of project, no. We would get it in the secondary market in volumes, in terms, that are appropriate for what our current market position and sales obligations might be.

MR. GOLDENBERG: But if New England is as short of gas capacity as the ISO New England, then doesn't somebody want to step up and buy firm transportation before there can be a secondary market if it's really short?

MR. LOCKETT: You make a good point. But when looking at a dollar-fifty/two dollars demand charges for X month capacity for 20 years, that is a mammoth commercial commitment that is outside what we would be looking at. Now, if it were a three-year commitment, the answer might be yes; if it was a five-year commitment we're probably on the edge of that. But we look at what we buy gas for, what we sell gas for, we're trying to hedge it for the appropriate term. You can't do it to those contracts, especially with three years down it road and they have a 20-year term after that, it's just way to risky for us. If we had power generation, we might look at it. But we don't have any power generation in ISO New England.

MR. RUDIAK: The question of firm gas, it's very important to look at the physical infrastructure into this region we're talking about. I just want to quickly summarize for everybody. So the LDC's have a peak day of about 4.2 BCF. There's 2.7 BCF of capacity. That's the constraint capacity that's trying to go from the Marcellus forward. On top of that, the LDC's have 1.4 BCF of LNG peaking. So that confirms essentially the LDC's design peak and the infrastructure is pretty well matched. Now, on top of that there's electric generation demand, and those numbers can range from 1 BCF to 2 BCF, depending upon the assumption of dual fuel. The reality is we have a winter reliability problem in New England. That gas -- I know Mr. Lockett and others have talked about the firm marketer contracts et cetera -- the reality is most of that gas, and we can even confirm that with the LNG importers here, comes from LNG imports. There's not necessarily anything wrong with that necessarily, but it does expose the system to a couple of risks: It exposes the system to whether or not LNG importers, at their discretion, are going to import supply at any particular time, whether or not the transportation arrangements are going to be in place or not; and it exposes a system to the world price of LNG. But the reality of the physical situation here, the New England region is highly dependent on electric

generation systems, natural gas is highly dependent upon LNG imports, it's the physical reality. So the fundamental question is: Does the waiver and a proposal to bolster the infrastructure from the Marcellus, is that in the policy interest, is that in the public interest of the New England region to avoid or reduce the risk associated with world LNG, LNG supply and availability for other risk factors or not?

We also know how difficult it is to add capacity in the New England region. We see the FERC has ordered the constitution pipeline, they issued a certificate. So the Tennessee-Connecticut project, those certificates have been issued. None of them have any near-term likelihood that they're going to be going into effect.

So in terms of adding capacity into this region, it takes a long time, it's really difficult and so the longer we wait, the more we're going to have this concern of higher and higher dependence on LNG imports, which is not necessarily a bad thing necessarily if the supply is always going to be there and it's always going to be there at a very low price, et cetera. But it's a risk, and it's a risk associated with physical infrastructure as the numbers that John Coyle was just describing. There's a very minimum amount of oil infrastructure. And the EDC's

proposals are generally designed to assist in bolstering that forwarding capacity. That's the infrastructure issue; it's not a back-haul issue, it's a forward-haul issue.

MS. FERNANDEZ: Richard next and then Tim.

MR. KRUSE: Just to comment on firm. "Firm" is a very slippier concept. We have through the Commission initiatives made firm into primary firm, secondary firm with in-pass, secondary firm out of path. And on a scheduling basis, the only thing that's committed that the pipeline can guarantee is if you submit your timeliness for a primary receipt point and a primary delivery point, that is firm. Everything else is interruptible. It may be scheduled under a primary firm contract, but if you're not going from the design receipt point to the design delivery point, there's a chance that it will not be scheduled. That is why when we look at what is being delivered on a firm basis we're looking at primary delivery points, primary receipt points, those are the power plants that have that lined up. Everything else, given our constraints, yes, they're moving understand a firm contract, but it is secondary, it is interruptible until it is scheduled. And if it doesn't get scheduled because of pipeline constraints, we have no obligation to go forward. So that's the risk. Any time the LDC's schedule up their firm contracts, they know what those receipt points are and

they can count on it if they submit it timely. What's left, the leftovers, is what is fuelling the gas-fired generators. And it is a winter peak problem. And back halls encounter constraints also. A lot of our generators are down laterals that become forward-hauls. So it is on Algonquin almost impossible to go anywhere to a marketplace without actually being a forward haul at some point. So there's constraints.

We've talked about a lot of constraints coming from the West, but there's some constraints on the laterals also. That's not to say that the power generators don't "buy firm gas." But if they don't get the gas, we can't provide it to them. We're operating at the limits of our system capability. I can't emphasize that too much. I mean, we are scheduling the system from the West to the East to the maximum extent possible. And anything above that, we're totally dependent on gas coming in on the east. And even then, during peak winter conditions, we're tight from that standpoint. So there's a severe infrastructure problem. You just heard from Tenaska why some of the major marketing firms are not able to step forward and sign up for capacity. The EDC's are willing to do that because they see the benefits for the consumers, and ultimately the benefit for their retail organizations. But we're not questioning the intelligence of anyone here. This is a

risky business and a capital intensive business and we're confident that everyone is trying to operate in their own best self-interest. But in the process, we need to make sure that the market that we have here is working for the benefit of the consumers and right now we would submit that it's not.

MR. HOWE: When the EDC's get the capacity and they have this energy reliability service, is their capacity manager going to be able to release pipeline ground service from a primary receipt point to a primary delivery point to electric generators?

MR. RUDIAK: Yes.

MR. BRENNAN: I just wanted to emphasize the point to the system that secondary firm is then available from is released to LDC's capacity. But to get to that point you have to get the LDC's to procure that capacity for their customers to make sure they don't need it for their customers, the competitive suppliers don't need it to serve those customers that are being served by the competitive suppliers. The LDC's have a right to the impact capacity for their customers' need before it's released to people like Mr. Lockett at Tenaska can use that capacity and release to a secondary firm to the secondary market. And all that's at issue here is very analogous, it's the EDC's buying on behalf of their electric customers

ultimately, having an opportunity to first make sure that that gas can be used by the generators supplier and customers ultimately. To the extent it's not and it's not needed and reliability is fine, it's again released to be used by others in the secondary market.

MS. FERNANDEZ: Vince and then Joe.

MR. MORRISSETTE: I just wanted to clarify a few comments on the LNG. First and foremost, we sell gas, we don't sell LNG, and we sell it at gas prices, regional gas prices. So we have a firm obligation to deliver. We will ensure that we have gas supply to back it up, whether it be LNG in our tank or some other source of gas supply. We hold primary firm on Maritimes which gets us into Algonquin and Tennessee. We can get back haul -- or it's not even called "back haul" anymore -- we can get capacity from east to west on Tennessee or Algonquin on a very reliable basis. We don't hold it long-term because it doesn't make economic sense to do so.

We currently have 25-year agreements in place for Brunswick and Maritimes and Canon Port capacity to the tune of about almost a million dollars a day in capacity charts. We pay well over $300 million a year and we're at risk of that; we don't pass it through to anybody, we're at risk for it. It's just based on the commodity we buy and the commodity we sell.

So we are very aware of buying capacity that the market doesn't need, underutilized capacity, all of those concepts, we live that every day. We operate at about probably now a 20 percent utilization factor. So, and the supply in Maritimes, as you know, the indigenous fleet is decreasing, so that actually may be going down a little bit. So to clarify that, because we do here that a lot, that we're exposed to the international LNG prices, et cetera. Those are declining, they're very low right now: Europe's currently under four dollars; Asia's under five dollars. That is expected to continue for the foreseeable future. There are a lot of LNG facilities, new supplies coming on line in the U.S. and elsewhere that will keep that price down. LNG supply is far outpacing LNG demand as far as growth goes.

So we don't see the LNG being any bigger risk than gas prices in the U.S. Indigenous supplies, just by comparison you've got roughly a 40 percent increase in LNG supply coming up on the world market, it's a 35-a-day BCF market. We have about 13 BCF coming on line in the next two years by 2018. That's almost, from a proportional standpoint, what happened with the Marcellus. So if you don't believe in LNG then you probably shouldn't believe in Marcellus either. But the supply is there, and will be there, and it's going to be cheap going forward and it

would be a shame not to use it as an effective portion of the New England gas supply market. Once again, just want to clarify that.

Thank you.

MR. DALTON: I agree with just about everything he said. I would associate myself with those remarks. I would also note, again, this came up with respect to and in the context to the electricity market, as I noted in an answer to the Commissioner earlier, we saw real evidence of the impact that LNG can have in the winters of '13-'14 and '14 and '15 where the level of imports nearly doubled and prices reduced by billions of dollars. Energist advisors, since we have done -- I think you've heard of just about every report except for this one -- so I commend to you a report done by Energist advisors, which the end conclusion is that much of this can be solved through contracting, not necessarily construction, so.

MR. HOWE: Do you have firm transportation contracts on Algonquin?

MR. DALTON: We do.

MS. FERNANDEZ: I have a question. Several I think some folks in the audience, and other people in the panel, this is directed to the EDC's, have said that you've made statements elsewhere saying that you intend to proceed with this project absent a waiver. And I know the folks

have spoken for you. Is that correct?

MR. DALY: If I may? That question was given to us in our proceeding in Massachusetts. And the answer we gave, and it's in the testimony we filed so we were very upfront about this. We said this waiver request is part of what we're looking for because it better aligns the causation with the benefits. And asked then would you go ahead with the project without that waiver? Our answer was: We think it was important for the states, we put it in there because the states were looking for that. It helped them in justifying having their EDC's contact for gas transportation because that hasn't been done in the deregulated world. As someone pointed out, this was normal business in the market industry, and still is in many parts of the country. So that's business as usual.

So the issue here is how New England has re-regulated, if I can call it that, or has implemented its competitive marketplace where the EDC's have not been in the fuel contracting business or the transportation business really.

So the states saw that as a way to link incurring these costs and ensuring that it goes back to the power generation sector in the first place and then to the general market after that. So it was important to the states that we pursue this. Would the project go ahead?

That depends on what the states approve. So the states haven't approved any of these contracts yet. And I think it would be helpful for them to give them clarity in terms of what the FERC's intention is or it could support what they want to do, or if FERC decides no, we don't want to do this because we have other considerations in the marketplace, then the states need to take that into consideration when they're looking into the EDC's in these contracts, but ultimately would go back to the states as to whether they support the EDC's going forward with a general release of capacity versus a targeted release. I think it helps. That doesn't mean they might not change their mind and decide not to do it, I mean, not all the states are aligned on what needs to be done here, so it's important that we get as many states on board as possible to support the program under the terms that we think are important to them.

MR. BRENNAN: I would just say that National Grid from the start of this, again as James said, we believe it is important to at least some of the states also, and ultimately we have a right in the contract and the precedent agreements to decide to whether we need to or will go forward it. And I'll tell you that even -- obviously, we're going to take a lot of the states' position into account, but I think National Grid itself is

not committed to moving forward at this point without those contracts. That's a decision that we have to see if we're comfortable with once this is settled.

MR. GOLDENBERG: For the EDC's, I didn't see much on how you were going or planning to arrange your asset manager. Are you going to use the traditional approach where the asset manager is going to pay you for the capacity at least something? Or are you going to be essentially paying a fee to the asset manager to manage the capacity?

Do you have any insight into how that is supposed to work?

MR. DALY: Yes, we see this asset manager, it's really an administrative position in terms of allocating capacity. Asset managers generally are paying us for them to give them a position on the pipeline, to give them capacity on pipelines. So they pay us and then they go and remarket that capacity for their own benefit. This we see as capacity manager is really an administrator to allocate the capacity to the marketplace and maximize the revenue back to our customers, not to themselves. So that's the overall view of it. And in terms of what the components may be, we still have to work out with the states but it's not a trading position. We want an entity that's more administrative in terms of getting that capacity going.

MR. GOLDENBERG: So the assets manager is actually going to hold the asset? It will be bundled sales in the event the generator didn't need the capacity. But that would mean that somebody would have to hold gas contracts.

Would that be the asset manager or would that be you?

MR. DALY: That could be the EDC and have the asset manager manage it. It's a question of it's a credit facility, it's how much credit and capital tied up in that big asset. So right now I think the EDC's would retain that. If in this structure there's an entity that comes forward that's of sufficient capital strength, it's better for them to have it, we'll consider that. But we don't have to have it with the asset manager.

MR. GOLDENBERG: Would the EDC's have gas supply contracts as well so that you can put gas in the LNG and you could make a bundled sale and use it?

MR. DALY: Well, we see the LNG tanks need to be filled up, so that predominantly would be purchased probably at City Gate prices filled up during the off-peak period and then made available at peak period, or whatever is a critical need on the system. And the sale of that asset, as I said earlier, is probably going to be at city gate prices, that's our proposal. Who actually holds the

title to that capacity, I don't think it matters for the function of the market much who does it, whether the EDC's still hold onto it and have somebody else administer it, or we have somebody else, a substantial financial entity with a high financial rating that actually takes title to it and then hands it back to us. So under our asset management agreements we do allow the asset manager to take all of that, but then hands us back the assets full with LNG at the end of their contract term. So we can do it either way.

MR. HOWE: The asset manager, are you actually going to do it past your release to the asset manager under the waiver request in order to do an asset manager time release? Or is the asset manager really going to be just your agent while you continue to hold the capacity?

MR. DALY: I think we can do it either way. There's an accomodation in the marketplace that works better, and people think there's an efficiency one way or the other, we're open to hear that. I think we can do it either way.

MR. HOWE: Do you have any insight or expectation at this stage as to how much of this capacity would be released for like the one year and two years and three years in advance, or as opposed to how much would be held for daily, intraday releases or bundled sales?

MR. DALY: That's a good question. We're going to have to solicit the market and find out, I mean, you heard from one marketer their appetite for going long, if you like, is multiyear, maybe one, two, three years. So we think there's a demand for that level of service, as well as seasonal service. We're also seeing some demand from new power generation. So all the new power generation in New England is virtually gas-fired generation. And the people who are building those plans and looking for finance are being asked by their banks where are they going to gets firm capacity, because they don't want to be subject to let's say pay-for-performance penalties under that. So there's a demand emerging from that market. But like a lot of the marketers have said here they're not interested in going 20 years. So we can get the capacity into the market by going 20 years, but they're looking at something like forward capacity market is three years forward and one year commitment. So they may have interest in doing four years forward with only one year after that to support there so they would have firm capacity. But, like a lot of marketers and generators, their desire to go longer just isn't there, so the demand, the customers just aren't there in the quantity needed to get a project like this built. So that's the role we would fulfill and then release it back on under shorter terms to be determined what the

duration of all of those are based on the demand from the marketplace. That's work we still have to do, we're not there yet in terms of this whole project, but that's our intention.

MR. GOLDENBERG: But as I understand Mr. Lockett's point earlier was that the structure, they would not be able to buy that capacity, and that's what he's asking for. If he's willing to go out three to five years but he's not eligible under the tariff provision to buy it, he'd have to get it after you did your generator auction if there's anything left over.

MR. DALY: Yes.

MR. GOLDENBERG: But if a generator wants to buy from a marketer, their marketer isn't eligible.

MR. DALY: Our first allocation is the generation and then after that to other marketers. I think in terms of if generation isn't using it, if generation's not using it and they want to release it to the marketplace, I mean, then that's something we can consider. What works for the marketplace better if people have a better proposal for it or if the Commission wants to condition certain parts of this in view they see works better with the marketplace, then we'll have to consider that. We've made a proposal, so that's what we're asking for. If the market sees it differently and we get that

acknowledged that there's better ways to make it work, we will consider it.

MS. FERNANDEZ: Are there any other questions?

MR. ADAMS: Can I make one comment? James is spot on that generators like ourselves, it's one thing for us to be asked to make a 20-year commitment at a price that is -- that has no correlation to value to what an independent generator would do. It is entirely feasible for us to, should the Access Northeast project go ahead, for James Daly and Calpine to negotiate a deal whereby we took capacity for three to five years. That's easily done, I don't think the waiver is necessary to achieve a transaction structure like that.

MR. COYLE: In answer to your earlier question, Anna, that you had heard people say that the EDC's would move forward with Access Northeast regardless of whether or not the waiver was granted. In this proceeding, the Exelon next year attached as attachment A, the application VPU 15-181, Mr. Daly's testimony is the first exhibit to that, Exhibit EBGJGB1. And the question and answer on page 74 of that testimony, lines 1 through 15, is the source of statements that the EDC's have said they've move forward without the exemption.

MR. LOCKETT: In the hypothetical scenario that Tenaska or any other marketing company would get the

capacity through a capacity release, it's still not clear to me if the electric reliability service rate schedule has defined as "shipper", "generator" or "EDC". That's all it is, it's no other party. I'm neither, it's not clear to me how exactly I would be able to qualify as shipper and therefore I can take on that release. If you could clarify that.

MR. KRUSE: Just a clarification, if I release the capacity to you, the rate schedule is not prohibited to you. You're entitled to take the capacity if it's released to you.

MR. LOCKETT: I believe the definition includes "replacement shipper" as well, does it not?

MR. KRUSE: Yes.

MR. LOCKETT: If I'm neither, the EDC nor a generator, I'm not sure I qualify as being a shipper.

MR. KRUSE: If the capacity is released to you, you can take service under ERS. There is no limitation on you being a generator or an EDC and reschedule ERS as currently drafted. It is an open access rate schedule available to anybody. You can sign up for it, we have a confined proceeding agreement. If you want capacity now, you can sign up. But in terms of what we're talking about here, if the EDC's, through their program or outside their program pursuant to the Commission rules, released it to a

marketer, they are a qualified shipper under ERS.

MR. HOWE: For the EDC's, in your comments, I would ask the same thing I asked of Algonquin, and you might coordinate, and that would be a history of each of the restructuring proceedings in the five New England states that did restructuring in the late '90's as to what gas-fired generation was held by the EDC's at that time, what transportation contracts were held to the extent you can get the contract demands under those contracts, what happened to the contracts in the restructuring proceedings, and then what happened to those contracts thereafter?

MR. RUDIAK: I had a question for my colleagues on the panel, particularly Mr. Adams and Ms. Barron. With respect to the circumstances that -- this is regarding the structural differences between the gas and electrical industry. In terms of any circumstances that would cause you an incentive to sign on for a long-term pipeline capacity, are there any circumstances whatsoever that you can envision or that you can describe? And if so, what are they?

MR. ADAMS: Well, John, the first thing is the big issue we have that keeps us from subscribing to capacity for the terms that Spectra is offering for their own good, we have to have some sort of guarantee on power revenue over the same period of time. It's difficult for

me to go to our shareholders and say, "I want to commit to 20 years of pipeline capacity" if I don't have an offset on revenue. Now, let me also kind of tweak that a little bit, because one of the -- just thinking generically, I don't want to get into confidential information -- but in the context of what of the plants that we've looked at in the past and adding FT, we had the opportunity to pick up FT and we'll say it was -- let's just say would it cost us $25 million a year for 20 years. So you do the math, that's half a billion dollars to meet the pipe supply capacity obligation. That capacity from point A to point B was probably in the money for the visible part of the curve, which is as Tom said is three to five years. But I could go out and spend $50 million and put in an oil tank and that's a one-time expense. That math is pretty compelling.

MS. BARRON: The only thing I would add is to the point Craig made earlier to dual fuel. The only point I would add is I don't think any of us up here would necessarily expect a guarantee of revenues. We don't get guaranteed revenues, we don't have rate regulation. But we do need to have some reasonable, foreseeable market price signal that we're going to be able to recover that cost. And right now prices just don't justify it.

MS. FERNANDEZ: I think Frank has a question. Kamala has a question.

MS. JAYARAMAN: I'm kind of curious in terms of supplier of gas, you said it's noneconomic in the sense of to see what is economic incentive to procure long-term capacity?

MR. MORRISSETTE: For the generators or from an economic standpoint?

MS. JAYARAMAN: No, for you when you said there was not --

MR. MORRISSETTE: Oh. On the market from Tennessee to Algonquin coming from east to west, it's readily available. So for us to take it for 20 years versus just taking it for the month we need it, the season we need it, a year or through in some cases an AMA, that's how we procure it. We can get it on as as-needed basis, or more or less on an as-needed basis on those pipes in the direction we're flowing. Now, if we had a commitment to serve somebody on one of those pipes, a long-term commitment, then we would certainly procure the capacity to meet that commitment.

MS. JAYARAMAN: So currently you don't have a need for it.

Do you have plenty of capacity?

MR. MORRISSETTE: We can get it if we need it. If we have a firm delivery obligation on those pipes, we can simply get capacity from Maritimes, from the Maritimes

interconnect to those points on Algonquin or Tennessee.

MS. JAYARAMAN: Thank you.

MS. FERNANDEZ: And I think we're getting close to the end here. Staff would like to take five minutes to talk amongst ourselves, and then we'll come back and talk about initial and reply comment deadlines, and if we have any further data requests. Just give us five minutes.

COMMISSIONER LaFLEUR: I probably won't come back after the five minutes. So I just wanted to say thank you to everyone.

MS. FERNANDEZ: Thanks, Commissioner.

(Whereupon a short recess is taken.)

MS. FERNANDEZ: I think we're ready to wrap it up. First, I'd like to thank the speakers here today for all the information they've provided, it was a very helpful, thank you very much. Thank you to the members in the audience for all the information, their questions. So Michael has a request for information that he'd like to ask before we break.

MR. GOLDENBERG: Yes, I'd like to ask Algonquin to provide any information they have on short-term non-biddable releases, the quantity of those releases as compared to daily or monthly releases just so we get an idea of what the release market is like for intraday releases.

MS. FERNANDEZ: Also, if you cited to a study or referred to a study here today, it would be helpful if you want to rely on that in your comments that you include a cite to that study in your comments.

MR. HOWE: A link.

MS. FERNANDEZ: Sure, a link.

So we would like to propose for comments that initial comments be due May 31st, it's a little bit more than 20 days, it's like the Tuesday after the holiday. Sorry. And then reply comments would be due ten days after that on June 10th. And we'll issue, if that sounds like a reasonable timeframe for folks. Let me know if that sound absolutely unworkable right now, please, otherwise, we'll issue a notice after this conference is over with those timelines.

Is that unworkable for anyone of the parties here?

Well, I think that's it, then. Thank you again everyone, and this concludes our technical conference.

(Whereupon the FERC technical conference held on Monday, May 9, 2016, was concluded at 3:45 p.m.)

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